REGIONAL HAZE FOUR-FACTOR ANALYSIS

Harvest Four Corners, LLC
Harvest Pipeline - San Juan 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 the 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 Harvest Four Corners, LLC (Harvest) that its Harvest Pipeline - San Juan Gas Plant (San Juan) facility was identified as one of the sources potentially contributing to regional haze at the Mesa Verde National Park Class I area.

In coordination with WRAP, the NMED devised criteria to determine specific equipment that is subject to the four-factor analysis. In the NMED's July 18, 2019 notification letter to Harvest, it specifies that any equipment with a potential to emit (PTE) greater than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) of Nitrogen Oxides (NO_X) or Sulfur Dioxide (SO_2) shall be included in this analysis. The subject equipment at San Juan, 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)	SO_2 Hourly PTE (lb/hr)	SO_2 Annual PTE (tpy)	SO_2 Subject to Analysis? (Yes/No)
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 1)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 2)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit 3)	56.3	246.4	Yes	0.060	0.26	No
Rolls-Royce Avon 1535 Natural Gas Turbine (Unit Rotating Spare)	56.3	246.4	Yes	0.060	0.26	No
Solar Centaur T4501 Natural Gas Turbine (Unit 4)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 5)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 6)	15.9	69.8	Yes	0.010	0.050	No
Solar Centaur T4501 Natural Gas Turbine (Unit 7)	15.9	69.8	Yes	0.010	0.050	No

Once the applicability of equipment and pollutants has been determined, potential retrofit control technologies must be identified. In accordance with 40 CFR 51 Appendix Y and at the recommendation of the NMED[1], this is primarily achieved by utilizing the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data. In order to determine the most relevant and current retrofit controls available, the RBLC is queried for the previous ten years. Summaries of the result of this search are provided and discussed under Section 2 of this report. Harvest 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/

NO_X is the only pollutant subject to evaluation in this four-factor analysis for the eight turbines located at San Juan. Unit 1 through 3 and Unit Rotating Spare are Rolls-Royce Avon model 1535 natural gas-fired, simple cycle turbines. Units 4 through 7 are Solar model Centaur T4501 natural gas-fired, simple cycle turbines.

Unit 1 through 3 and Unit Rotating Spare are rated at 15,000 horsepower and were manufactured in 1985 or 1986. Units 4 through 7 are rated at 3,735 horsepower and were manufactured in 1986.

Per NMED Guidance received on 9/23/2019, the four-factor analysis is to be completed only for units which are a steady state source of emissions. Unit Rotating Spare is a backup unit, which only operates when Unit 1, 2 or 3 are down for maintenance or repair. The unit is kept in a warehouse and is not a source of emissions unless it is commissioned to replace one of the primary turbines. Due to the intermittent nature of emissions and non-steady state operation, no further assessment of Unit Rotating Spare will be included in this four-factor analysis.

2.1. 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 San Juan are simple cycle turbines.

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

The significance of prompt NO_X is negligible in comparison to thermal and fuel NO_X. Fuel NO_X will also be negligible for San Juan'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.

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

The PTE from each turbine is reported in the facility's New Source Review (0613-M10R2) and Title V (P124-R3) permits, as well as summarized in Table 1 of this report.

2.1.2. Potential NO_X Controls for a Combustion Turbines

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

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

Table 2. Potential Control Options for Combustion Turbines

Control Equipment	Technically Feasible for Rolls-Royce (Units 1 through 3)?	Technically Feasible for Solar (Units 4 through 7)?	NO_X Control Efficiency
Good Combustion Practices	Yes	Yes	Base Case
Improved Combustion Technology	No	Yes	65% - 75%
Water/Steam Injection	No	No	N/A
Selective Catalytic Reduction	No	Yes	65% - 75%

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 San Juan. However, these practices have been developed and are currently in use at San Juan, as required by various conditions in its Title V and NSR permit authorizations. No further assessment of these control practices is included in this report.

2.1.2.2. Improved Combustion Technology

The improved combustion technology control option, commonly referred to as Dry Low Emissions (DLE) control, seeks to reduce the combustion temperature and residence time of fuel in the combustor (thereby decreasing NO_X

[4] Ibid.

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.

2.1.2.2.1 Rolls-Royce Avon Units

The Rolls-Royce Avon energy gas turbine and compressor business is currently owned and operated by Siemens. Based on communication with Siemens, there are no DLN control options for the model of turbines located at San Juan. The units were designed and manufactured prior to the enhanced environmental awareness present today; and therefore, were not designed to suitably implement emissions control measures. The unavailability is also likely due to lack of market demand to improve the control efficiency of these older units.

Per conversations with a Siemens representative, a small number of these turbine models were retrofit with DLN emissions controls as a pilot study, but the units did not function properly after installation of the control. Therefore, testing of DLN controls for these turbines was halted and the control eliminated as a viable option. DLN controls were not offered to the market to control emissions from these units.

Per 40 CFR Part 51, Appendix Y, "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term."[5] Further, source owners are not expected to "construct a process or control device that has not already been demonstrated in practice."[6]

DLN controls are not currently offered on the market for these turbines; therefore, this control is not considered to be available as described above. Additionally, there is historical precedent which indicates that installation of these controls would result in decreased functionality of the units. For these reasons, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.2.2 Solar Units

The improved combustion technology available for the units at San Juan is produced by the manufacturer of the units, Solar, and is called $SoLoNO_X$. Based on communication with Solar, $SoLoNO_X$ is available for the T4501 Solar turbines located onsite; however, each of the units would need to be uprated to model Centaur T4701 in order to support the technology. The uprate is necessary because installation of $SoLoNO_X$ requires the turbine combustors to be capable of handling significantly higher temperatures. Uprating the units involves replacing the combustor section of the turbine with a much larger and more robust combustor. Solar can guarantee an output NO_X concentration of 25 parts per million (ppm) for uprated units with $SoLoNO_X$ installed, resulting in a NO_X emissions reduction of approximately 65 - 75%, based on the 2016 hourly emission rate and turbine stack parameters of each unit.

Improved combustion technology was identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists this as an available control technique for gas turbines.[7] Therefore, it has been determined that this control technology is technically feasible for the Solar turbines located at San Juan.

[5] 40 CFR 51, Appendix Y, Section IV.D.2
[6] 40 CFR 51, Appendix Y, Section IV.D.1
[7] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

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. Additionally, the latent heat of vaporization from the flame zone is absorbed when water injection is utilized, further reducing the combustion temperature. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.[8]

2.1.2.3.1 Rolls-Royce Avon Units

Water/steam injection was identified in this review of RBLC as a potential control of NO_X emissions from natural gas-fired combustion turbines, and AP-42 Section 3.1 also lists water/steam injection as an available control technique for gas turbines.[9] However, communication with Siemens has indicated that water/steam injection is not currently offered for the model of turbines located at San Juan, and is therefore not considered available. Additionally, as this technology has not been installed on this model of turbine, there is no historical data to support that installation of these controls would result in significant reductions of NO_X emissions. For these reasons, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.3.2 Solar Units

Steam injection is not discussed as an option for these units because Solar does not manufacture turbines with steam injection technology. The capability of these units to be retrofit for water injection is dependent on the number of shafts employed in the unit, per communication with Solar. The shaft is the piece of equipment in the unit that is turned by the turbine to generate work. Solar has indicated that turbine units with one shaft are mechanically capable of installing water injection, while two-shaft units are not. The Solar Model T4501 turbines located at San Juan are one-shaft units and are, therefore, capable of being retrofit with water injection controls.

Despite the Solar T4501 being 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. They have stated that if there were direct modifications made to the turbine engine or it's supporting hardware, it could affect the unit's warranty with Solar.

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 account leaks and evaporative losses that would occur during transport. The facility is located in San Juan County, in the northwestern part of the state. The National Drought Mitigation Center currently classifies this region as

[8] Ibid.
[9] Ibid.

experiencing severe drought conditions.[10] The New Mexico Office of the State Engineer projects that the water demand in the San Juan region will exceed the drought-adjusted available water supply before 2030.[11] The implementation of this control may pose an unsustainable burden on this region's watershed.

Based on the communication with the turbine manufacturer detailed above, as well as the lack of available water in the region, it has been determined that water injection control is technically infeasible for the Solar turbines located at San Juan.

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 of a combustion unit. Within a reactor vessel containing a metallic or ceramic catalyst, the injected reagent reacts selectively with the NO_X in the exhaust to produce molecular nitrogen (N_2) and water (H_2O).[12] The chemical reactions for this process are shown in the equations below.

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

An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the quantity of reagent injected as a function of turbine load, speed, and temperature, so NO_X emissions reductions can be achieved. The lifespan of the catalyst is primarily determined by poisoning of active sites by flue gas constituent; thermal sintering, or compacting, of active 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.[13]

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 can blind the catalyst and may necessitate the application of a soot blower.[14]

For an 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.[15]

2.1.2.4.1 Rolls-Royce Avon Units

As provided by site engineers, the exhaust temperature of the Rolls-Royce Avon turbines is 1,250 °F, and is therefore outside of the temperature range necessary to support SCR control. It is unlikely that SCR control would function effectively on the Rolls-Royce turbines due to the high exhaust temperature of these units. Additionally,

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[10] Brian Fuchs, National Drought Mitigation Center, "United States Drought Monitor – New Mexico", https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?NM
[11] State of New Mexico Interstate Stream Commission, Office of the State Engineer, "San Juan Basin Regional Water Plan 2016", Figure ES-3. Available Supply and Projected Demand.
[12] U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
[13] Ibid.
[14] Ibid.
[15] U.S. EPA, AP-42, Section 3.1, "Stationary Gas Turbines"

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

Furthermore, Harvest does not anticipate that the current electricity availability at San Juan will be sufficient to support the substantial energy burden associated with SCR control. Installation of this control will require the facility to expand its current power generation.

Communication with Siemens has indicated that SCR controls are available for the turbine model assessed here. However, it is not anticipated that the exhaust temperature, space, and energy limitations can be overcome. Therefore, it has been determined that this control technology is infeasible for the Rolls-Royce turbines located at San Juan.

2.1.2.4.2 Solar Units

The exhaust temperature of the turbines assessed here is within the necessary operating range for SCR control, at approximately 827 °F. However, the site-specific space and energy limitations discussed above apply to these units as well.

Communication with Solar has indicated that SCR controls are available for the Solar turbines assessed here. Therefore, assuming that the space limitations can be overcome, SCR is considered a technically feasible control option for the turbines located at San Juan. Solar has estimated that installation of SCR control on these units will result in an output NO_X concentration of 25 parts per million (ppm), resulting in a NO_X emissions reduction of approximately 65 - 75%, based on the 2016 hourly emission rate and turbine stack parameters of each unit.

Harvest 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.[16] Cost effectiveness considerations for each unit and control technology are discussed below.

These cost estimates have been developed based on the actual emissions from each unit assessed here, using the 2016 Emission Inventory submittal for San Juan. The full cost estimation for each unit, including the EPA Air Pollution Control Cost Spreadsheet, is included in Appendix B of this report.

3.1. SOLAR TURBINES

Cost effectiveness for each technically feasible Solar combustion turbine control option are summarized Table 3.

Table 3. Cost Analysis Summary of Technically Feasible Control Options for Solar Turbines

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)*	Emission Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology (SoLoNO$_X$)	4	563,300	69,637	35.7	1,952
	5	563,300	69,637	28.9	2,412
	6	563,300	69,637	36.8	1,894
	7	563,300	69,637	46.4	1,500
Selective Catalytic Reduction **(SCR)**	4	4,000,000	457,586	35.7	12,824
	5	4,000,000	456,964	28.9	15,825
	6	4,000,000	457,827	36.8	12,455
	7	4,000,000	458,936	46.4	9,883

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

3.1.1. Improved Combustion Technology

Harvest has received an estimated direct capital cost for the equipment and vendor labor associated with implementing SoLoNO$_X$ on the turbines located at San Juan from Solar. Solar has also provided an estimated annual cost necessary to operate and maintain the units post-retrofit.

This cost estimate assumes that SoLoNO$_X$ will reduce NO$_X$ emissions to an outlet concentration of 25 ppm, based on manufacturer's estimations.

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

3.1.2. SCR

Harvest has received an estimated direct capital cost for the equipment and vendor labor associated with implementing an SCR system on the model of turbines located at San Juan from the manufacturer.

The EPA Air Pollution Control Cost Spreadsheet for SCR is used to estimate the direct annual costs (maintenance, operating labor, reagent cost, electricity cost, and catalyst cost) and indirect annual costs associated with Harvest's internal labor, overhead and capital recovery for the project.

This cost estimate assumes that the SCR will reduce NO_X emissions to an outlet concentration of 25 ppm, based on manufacturer's estimations.

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 Harvest'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. SOLAR TURBINES

4.1.1. Improved Combustion Technology

Harvest estimates that approximately 2-3 years will be needed to implement the improved combustion technology control equipment (SoLoNO$_X$). Factors that have been considered for this anticipated timeline include budgeting, design, uprating the combustors, procuring the equipment, and installing the control.

4.1.2. SCR

Harvest estimates that approximately 2-3 years will be needed to budget, plan, order, deliver and install the SCR control equipment.

This section addresses the potential energy and non-air environmental impacts that installation of the technically feasible control options poses 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. SOLAR TURBINES

5.1.1. Improved Combustion Technology

It is not anticipated that installation of the improved combustion technology (SoLoNO$_X$) on the Solar turbines at San Juan will have any significant energy or non-air environmental impacts.

5.1.2. SCR

The implementation of SCR on the turbines at San Juan would result in several energy and non-air environmental impacts. The primary impact of this control would be a significant increase in energy consumption, which would be necessary to power the units. The estimated energy consumption for each unit is summarized in Table 4, and is based on the EPA Air Pollution Control Cost Manual.[17] The calculation for these values is included in Appendix C of this report. Harvest does not anticipate that the current electricity availability at San Juan will be sufficient to support this increased energy burden. Installation of this control will require the facility to expand its current power generation. The costs of this associated power expansion are not accounted for in the SCR cost estimates included in Table 3.

Table 4. Turbine SCR Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh/yr)
4	95.8
5	100.1
6	99.2
7	97.3
Total	392.4

In addition to the increased energy burden, there are several non-air environmental impacts associated with the handling and storage of the reagent used in the SCR system, typically ammonia or urea. Ammonia is a Toxic Air Pollutant (TAP) regulated under 20.2.72.502 NMAC with an occupational exposure limit (OEL) of 18 mg/m^3. In both soil and water, urea is hydrolyzed quickly to ammonia and carbon dioxide by urease, an extracellular enzyme that originates from microorganisms and plant roots.[18] Short-term inhalation exposure to high levels of ammonia

[17] 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
[18] U.S. EPA, EPA/635/R-10/005F, "Toxilogical Report of Urea", July 2011

in humans can cause irritation and serious burns in the mouth, lungs, and eyes. Chronic exposure to airborne ammonia can increase the risk of respiratory irritation, cough, wheezing, tightness in the chest, and impaired lung function in humans. Animal studies also suggest that exposure to high levels of ammonia in air may adversely affect other organs, such as the liver, kidney, and spleen.[19]

Unavoidable releases of ammonia could have significant and irreversible impacts on the living and physical environment affected. Storage and handling of urea or ammonia onsite would result in an increased risk to the health and safety of facility operators. San Juan is a natural gas processing plant, which already maintains a high level of health and safety risk. Harvest considers any increase to this risk unacceptable.

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

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.[20]

Based on their current age and operating efficiency, it is estimated that the remaining useful life of the Solar turbines will be longer than the control units. The turbines have operated for more than 30 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 control device considered.

6.1. SOLAR TURBINES

6.1.1. Improved Combustion Technology

It is anticipated that the estimated useful life of the improved combustion technology, SoLoNO$_X$, will be similar to the useful life of an SCR system. The useful life is estimated to be 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[21]

6.1.2. SCR

The estimated useful life of the SCR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual.[22]

[20] 40 CFR 51, Appendix Y, Section II.B.4.f
[21] 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
[22] Ibid.

Based on a comprehensive review of the RBLC, available literature, and manufacturer's input of the available control technologies for the natural-gas fired turbines located at San Juan, Harvest has determined that there are no technically feasible control options for the Rolls-Royce turbines that are not currently implemented at the facility due to the age of the units.

At this time, Harvest would like to advise the NMED of additional concerns regarding the retrofit of the Rolls-Royce turbines. The manufacturer of these turbines, Siemens, is based out of Switzerland. Harvest is required to ship the turbines overseas for any necessary retrofits, repairs, or advanced maintenance requirements. This requires the turbine to be decommissioned and shipped via rail or truck across the country to an eastern port. From there, the turbine must be shipped via cargo ship to a port in Europe where it is then transferred via truck or rail again to Siemens for the applicable repairs/retrofits. Altering these turbines will undoubtedly increase operational complexity and will necessitate additional support from Siemens, contributing to severe cost implications.

Harvest has further determined that SoLoNO$_X$ and SCR are the only technically feasible control options for the Solar turbines. The cost of compliance to install the controls on each of these units has been estimated based on manufacturer's input, as well as the EPA Air Pollution Control Cost Manual.[23] The estimated cost effectiveness and NO$_X$ emission reduction for each unit are summarized in Table 5.

Table 5. Cost Effectiveness and NO$_X$ Reduction for Control of the Solar Turbines at San Juan

Control Equipment	Unit	NO$_X$ Reduction (tpy)	Cost Effectiveness ($/ton)
Improved Combustion Technology (SoLoNO$_X$)	4	35.7	1,952
	5	28.9	2,412
	6	36.8	1,894
	7	46.4	1,500
Selective Catalytic Reduction	4	35.7	12,824
	5	28.9	15,825
	6	36.8	12,455
	7	46.4	9,883

It is projected that the useful life of these units will be 20 years, based on the life expectancy of the SoLoNO$_X$ and SCR controls. The primary energy and non-air impacts from the SCR control method is increased energy consumption and health and safety risks associated with ammonia usage. Harvest estimates an achievable compliance timeline to implement either the SoLoNO$_X$ or SCR controls is 2-3 years.

[23] 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

Furthermore, Harvest would like to advise the NMED of their judgement that the San Juan facility's potential contribution to regional haze at the Mesa Verde National Park Class I area is such that it does not justify their facility being selected for this assessment. There are hundreds of sources, both major and minor, located closer to the Class I area whose contribution has not been considered. Harvest would argue that only assessing high emitting sources at a limited number of facilities will not effectively address the visibility impairment problem, as required by the State under the RHR.

8. SUPPORTING DOCUMENTATION

Appendix A – RBLC Tables
Appendix B – Cost Analysis Calculations
Appendix C – SCR Energy Consumption Calculation

APPENDIX A - RBLC TABLES

RBLC Analysis for Natural Gas Fired Turbines – NO_X Control

	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]
IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	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.	Solar Units - Technically feasible Rolls-Royce Units - Technically infeasible. This option is not available for the Rolls-Royce turbine model.	Technically infeasible. This option is not available for the turbine models assessed.	Solar Units - Technically feasible Rolls-Royce Units - Technically infeasible. This option is not available for the Rolls-Royce turbine model.
RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	65 - 75%		65 - 75%

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/311nscr.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 09/19/2019

RBLCID	FACILITY NAME	EPA REGION	PERMIT NUM	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	STANDARAD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	COST EFFECTIVENESS	INCREMENTAL COST EFFECTIVENESS	Cost Verified	DOLLAR YEAR USED IN COST ESTIMATES
AK-0083	KENAI NITROGEN OPERATIONS	10	AQ0083CPT06	Five (5) Natural Gas Fired Combustion Turbines	16.11	Natural Gas	37.6	MMBTU/H	Five (5) Natural Gas-Fired Solar Combustion Turbines rated at 37.6 MMBtu/hr each. Installed in 1976.	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0			0	0	N	
CA-1215	QUALCOMM INC.	9	2012--APP-002100	Cogeneration gas turbine	16.11	natural gas	4.37	MW	Manufacturer: Solar Turbines- Model: Mercury 50-6400R	Nitrogen Oxides (NOx)	A	SoLoNOx burner (Ultra lean Premix)	0			0	0	N	
LA-0331	CALCASIEU PASS LNG PROJECT	6	PDS-LA-805	Aeroderivative Simple Cycle Combustion Turbine	16.11	Natural Gas	263	MM BTU/h		Nitrogen Oxides (NOx)	B	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	0			0	0	N	
MI-0410	THETFORD GENERATING STATION	5	191-12	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	16.11	natural gas	171	MMBTU/H	Two natural gas fired simple cycle combustion turbines each with an electrical generator (nominal 13MW each; 171 MMBtu/hr heat input rating each). Each turbine is limited to 343 MMscf of natural gas per 12-month rolling time period as determined at the end of each calendar month. Both turbines combined are limited to 5.15 MMscf of natural gas each calendar day.	Nitrogen Oxides (NOx)	P	Dry low-NOx combustors	0			0	0	N	
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	5	185-15	FG-TURBINES	16.11	Natural gas	10504	HP	Five (5) simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines. The turbines are identified as EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, and EUTURBINE5 within the flexible group FGTURBINES. There shall be no more than a combined total of 5 events (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 (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners	0			0	0	N	
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	5	185-15A	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	16.11	Natural gas	10504	HP	Five simple cycle natural gas-fired combustion turbines (CTs) to drive compressors that will be used to transport natural gas through pipelines (EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5 in FGTURBINES). There shall be no more than a combined total of 5 events (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 (ISO).	Nitrogen Oxides (NOx)	A	Dry ultra-low NOx burners.	0			0	0	N	
NV-0050	MGM MIRAGE	9	825	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	16.11	NATURAL GAS	4.6	MMBTU/H	THE TWO UNITS ARE IDENTICAL SOLAR MERCURY COMBUSTION GAS TURBINES FOR ELECTRIC POWER GENERATION. EACH UNIT IS RATED AT 4.6 MMBTU/HR, AND IS ALLOWED TO OPERATE 24 HOURS/DAY AND 8,760 HOURS/YEAR.	Nitrogen Oxides (NOx)	P	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU		0	0	N	
OK-0148	BUFFALO CREEK PROCESSING PLANT	6	2012-1026-C PSD	Small Combustion Turbines (<25MW)	16.11	Natural Gas	10179	Horsepower	Solar Taurus 70-10802S times 2.	Nitrogen Oxides (NOx)	P	Dry-Low NOx Combustion	0			0	0	N	
OK-0153	ROSE VALLEY PLANT	6	2012-1393-C PSD	TURBINES 9,443-HP SIEMENS SGT-200-2S	16.11	NATURAL GAS	9443	HP	THERE ARE TO BE LIKE-KIND TURBINES	Nitrogen Oxides (NOx)	P	DRY LOW-NOx COMBUSTION.	0			0	0	N	
*PA-0314	BEECH HOLLOW	3	63-00922D	COMBUSTION TURBINE without DUCT BURNERS UNIT	16.11	Natural Gas	2433	MMBtu/hr	CEMS for NOx, CO	Nitrogen Oxides (NOx)	A	SCR	0			0	0	N	
TX-0642	SINTON COMPRESSOR STATION	6	PSDTX1304	Compression Turbine	16.11	natural gas	20000	hp	Two (2) 20,000 horsepower Solar Titan 130S turbines in natural gas pipeline compression service	Nitrogen Oxides (NOx)	P	Solar's SoLoNOx dry emission control technology	0			0	0	N	
TX-0685	GUADALUPE GENERATING STATION	6	106011 PSDTX1310	(2) simple cycle turbines	16.11	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	B	DLN burners, limited operation	0			0	0	N	
*WI-0283	AFE, INC. â€“LCM PLANT	5	17-JJW-207	P90 â€“ Natural Gas-Fired Emergency Generator	16.11	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Nitrogen Oxides (NOx)	P	Good Combustion Practices and the Use of Turbocharger and Aftercooler	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINES S35-S36	16.11	NATURAL GAS	12555	HP	TWO (2) 12,555 HP SOLAR MARS 100-15000S TURBINES	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	
WY-0067	ECHO SPRINGS GAS PLANT	8	MD-7837	TURBINE S34	16.11	NATURAL GAS	3856	HP	SOLAR CENTAUR 40-T4700S	Nitrogen Oxides (NOx)	N	SOLONOX	0			0	0	N	

APPENDIX B - COST ANALYSIS CALCULATIONS

Harvest Four Corners, LLC

San Juan Gas Plant

Turbine Cost Analysis Interest Rate: 5.50%

All Units Period (yrs): 20

Solar Centaur T4501					
Control Equipment	**Unit**	**Capital Cost ($)**	**Total Annual Cost* ($)**	**Emission Reduction (tpy)**	**Cost Effectiveness ($/ton)**
Improved Combustion ($SoLoNO_X$)	4	563,300	69,637	35.7	1,952
	5	563,300	69,637	28.9	2,412
	6	563,300	69,637	36.8	1,894
	7	563,300	69,637	46.4	1,500
Selective Catalytic Reduction (SCR)	4	4,000,000	457,586	35.7	12,824
	5	4,000,000	456,964	28.9	15,825
	6	4,000,000	457,827	36.8	12,455
	7	4,000,000	458,936	46.4	9,883

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

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 4	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (85.08 ppm)				
NO_X ppm:		85.08	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		50.53	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		14.85	tpy	
Total Cap Investment	$	563,300		<-- from Solar
Annualized TCI:	$	47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	69,637		
Emissions Reduction:		35.68	tpy	
Cost Effectiveness:	**$**	**1,951.57**	**$/ton**	

SCR (25 ppm)				
NO_X guarantee:		25	ppm	<-- Estimated based on control efficiency
NO_X tpy:		14.85	tpy	
Total Cap Investment	$	4,000,000		<-- Vendor estimate
Annualized TCI:	$	334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	122,869		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	457,586		
Emissions Reduction:		35.68	tpy	
Cost Effectiveness:	**$**	**12,823.90**	**$/ton**	
Incremental Cost:	$	10,872.32	$/ton	

Unit 4: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

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

What type of fuel does the unit burn?

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)?	23.66	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual fuel consumption?	186,400,000	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 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

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 (NOx_{in}) to SCR	0.54	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.159	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.

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

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.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

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	CEPCI = Chemical Engineering Plant Cost Index
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}$)	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	

Unit 4: 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 =	24	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	207,295,163	scf/Year	
Actual Annual fuel consumption (Mactual) =		186,400,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.899	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7877	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	70.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.06	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	35.68	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} =	10,960	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	120.19	/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 =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	12.0	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})	91.18	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	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 $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	3.6	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} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	12	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

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 $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	12.17	kW

Unit 4: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$120,001	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,669	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 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,743	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,479	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,178	in 2018 dollars
Direct Annual Cost =		$120,001	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,669	per year in 2018 dollars
NOx Removed =	35.68	tons/year
Cost Effectiveness =	$12,826	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC
San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 5	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (71.29 ppm)				
NO_X ppm:		71.29	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		44.47	tpy	<-- From 2016 EI calculations

SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		15.59	tpy	
Total Cap Investment	$	563,300		<-- from Solar
Annualized TCI:	$	47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	69,637		
Emissions Reduction:		28.88	tpy	
Cost Effectiveness:	**$**	**2,411.59**	**$/ton**	

SCR (25 ppm)				
NO_X guarantee:		25	ppm	<-- Estimated based on control efficiency
NO_X tpy:		15.59	tpy	
Total Cap Investment	$	4,000,000		<-- Vendor estimate
Annualized TCI:	$	334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	122,246		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	456,964		
Emissions Reduction:		28.88	tpy	
Cost Effectiveness:	**$**	**15,825.12**	**$/ton**	
Incremental Cost:	$	13,413.53	$/ton	

Unit 5: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

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

What type of fuel does the unit burn?

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)?	23.52	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual fuel consumption?	194,600,000	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 | 5600 | Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

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 (NOx_{in}) to SCR	0.46	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.160	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.

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

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.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

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	CEPCI = Chemical Engineering Plant Cost Index
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}$)	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	

Unit 5: 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 =	24	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	206,055,361	scf/Year	
Actual Annual fuel consumption (Mactual) =		194,600,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.944	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8273	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	64.9	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	6.98	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	28.88	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.81		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,894	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	131.10	/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 =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	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})	83.10	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	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 $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	51	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 =	9	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 t

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.	12.10	kW

Unit 5: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$119,378	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,046	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 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,029	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,764	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$1,985	in 2018 dollars
Direct Annual Cost =		$119,378	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,046	per year in 2018 dollars
NOx Removed =	28.88	tons/year
Cost Effectiveness =	$15,828	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 6	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		
Base (82.57 ppm)				
NO_X ppm:		82.57	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		52.72	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		15.96	tpy	
Total Cap Investment	$	563,300		<-- from Solar
Annualized TCI:	$	47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	69,637		
Emissions Reduction:		36.76	tpy	
Cost Effectiveness:	**$**	**1,894.45**	**$/ton**	
SCR (25 ppm)				
NO_X guarantee:		25	ppm	<-- Estimated based on control efficiency
NO_X tpy:		15.96	tpy	
Total Cap Investment	$	4,000,000		<-- Vendor estimate
Annualized TCI:	$	334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	123,110		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	457,827		
Emissions Reduction:		36.76	tpy	
Cost Effectiveness:	**$**	**12,455.07**	**$/ton**	
Incremental Cost:	$	10,560.63	$/ton	

Unit 6: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

What type of fuel does the unit burn?

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

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)?	22.78	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual fuel consumption?	192,900,000	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 5600 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

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 (NOx_{in}) to SCR	0.55	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.165	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.

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

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.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

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	CEPCI = Chemical Engineering Plant Cost Index
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}$)	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	

Unit 6: 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 =	23	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	199,551,724	scf/Year	
Actual Annual fuel consumption (Mactual) =		192,900,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.967	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8468	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	69.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	8.68	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	36.76	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.87		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,550	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	121.13	/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 =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.0	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})	87.10	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	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 $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	3.6	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} =	3	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	12	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to t

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 $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial turbines.	11.71	kW

Unit 6: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$120,242	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$457,910	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 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,856	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,705	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,081	in 2018 dollars
Direct Annual Cost =		$120,242	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$457,910	per year in 2018 dollars
NOx Removed =	36.76	tons/year
Cost Effectiveness =	$12,457	per ton of NOx removed in 2018 dollars

Harvest Four Corners, LLC

San Juan Gas Plant

Solar Centaur 40	Interest Rate:		5.50%	
Unit 7	Period (yrs):		20	<-- EPA Cost Control Manual
	Model:	T4501		

Base (102.54 ppm)				
NO_X ppm:		102.54	ppm	<-- Converted from 2016 EI calculations and data
NO_X tpy:		61.41	tpy	<-- From 2016 EI calculations
SoLoNO$_X$ (25 ppm)				
NO_X guarantee:		25	ppm	<-- from Solar
NO_X tpy:		14.97	tpy	
Total Cap Investment	$	563,300		<-- from Solar
Annualized TCI:	$	47,137		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	22,500		<-- from Solar
Total Annual Costs:	$	69,637		
Emissions Reduction:		46.44	tpy	
Cost Effectiveness:	**$**	**1,499.58**	**$/ton**	
SCR (25 ppm)				
NO_X guarantee:		25	ppm	<-- Estimated based on control efficiency
NO_X tpy:		14.97	tpy	
Total Cap Investment	$	4,000,000		<-- Vendor estimate
Annualized TCI:	$	334,717		<-- Based on interest rate, year and TCI
Annual O&M Costs:	$	124,219		<-- from Cost Control Spreadsheet
Total Annual Costs:	$	458,936		
Emissions Reduction:		46.44	tpy	
Cost Effectiveness:	**$**	**9,882.87**	**$/ton**	
Incremental Cost:	$	8,383.30	$/ton	

Unit 7: Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial turbine?

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

What type of fuel does the unit burn?

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)?	23.03	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,000	Btu/scf
What is the estimated actual annual fuel consumption?	189,200,000	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 | 5600 | Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

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 (NOx_{in}) to SCR	0.65	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.158	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.

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

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.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

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.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used

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	CEPCI = Chemical Engineering Plant Cost Index
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}$)	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	

Unit 7: 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 =	23	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	201,751,917	scf/Year	
Actual Annual fuel consumption (Mactual) =		189,200,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.938	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8215	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	75.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.31	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	46.44	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.95		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	10,667	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	110.64	/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 =			Not applicable; factor applies only to coal-fired turbines
Elevation Factor (ELEVF) =	14.7 psia/P =	1.23		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.0	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})	96.41	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	11	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 $A_{catalyst}$	13	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	3.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	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} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to t

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.	11.84	kW

Unit 7: Cost Estimate

Total Capital Investment (TCI)

TCI for Natural Gas-Fired Turbines		
Total Capital Investment (TCI) =	$4,000,000	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$121,351	in 2018 dollars
Indirect Annual Costs (IDAC) =	$337,668	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$459,019	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 x TCI =	$20,000	in 2018 dollars
Annual Operating Cost =	Operator Labor Rate x Hours/Day x t_{SCR} =	$87,600	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$4,872	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,577	in 2018 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$2,303	in 2018 dollars
Direct Annual Cost =		$121,351	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$334,800	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$337,668	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$459,019	per year in 2018 dollars
NOx Removed =	46.44	tons/year
Cost Effectiveness =	$9,885	per ton of NOx removed in 2018 dollars

APPENDIX C – ENERGY CONSUMPTION CALCULATION

SCR Energy Usage Summary

Turbine SCR Energy Consumption Analysis Summary

Unit	Annual Energy Consumption (MWh)
4	95.8
5	100.1
6	99.2
7	97.3
Total	392.4

SCR Energy Usage Calculation

Unit: 4

Equation:	Electricity Consumption, kW =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.66	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.366		
	Unit 4 2016 Operating hours =	7,877.00	hours	2016 EI Submittal
	Electricity Consumption =	12.2	kW	
	Annual Electricity Consumption =	95.8	MWh/yr	

SCR Energy Usage Calculation

Unit: 5

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.52	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.352		
	Unit 5 2016 Operating hours =	8,273.00	hours	2016 EI Submittal
	Electricity Consumption =	12.1	kW	
	Annual Electricity Consumption =	100.1	MWh/yr	

Harvest Four Corners, LLC
San Juan Gas Plant

SCR Energy Usage Calculation
Unit: 6

Equation:	Electricity Consumption, kW =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$		Source: EPA Cost Spreadsheet
Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	22.78	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.278		
	Unit 6 2016 Operating hours =	8,468.00	hours	2016 EI Submittal
	Electricity Consumption =	11.7	kW	
	Annual Electricity Consumption =	99.2	MWh/yr	

SCR Energy Usage Calculation

Unit: 7

Equation: Electricity Consumption, kW = $A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ Source: EPA Cost Spreadsheet

Where:	A =	0.1 x QB		EPA Cost Spreadsheet for industrial turbines
	QB =	23.03	MMBTU/hr	Maximum Annual Heat Input Rate
	CoalF =	1.0		EPA Cost Spreadsheet value for Oil and Natural Gas
	Heat Rate Factor (HRF) =	NPHR / 10		
	Net Plant Heat Input Rate (NPHR) =	8.2	MMBtu/MW	Default EPA Cost spreadsheet value
Calculation:	HRF =	0.82		
	A =	2.303		
	Unit 7 2016 Operating hours =	8,215.00	hours	2016 EI Submittal

Electricity Consumption =	11.8	kW
Annual Electricity Consumption =	97.3	MWh/yr