

PM_{2.5} SIP Evaluation Report:

PacifiCorp Energy – Gadsby Power Plant

Utah PM_{2.5} Serious SIP

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

July 1, 2018

DAQ-2018-006882

PM_{2.5} SIP EVALUATION REPORT

PacifiCorp Energy – Gadsby Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for Section IX, Part H.12 of the Utah SIP; to address the Salt Lake City PM_{2.5} Nonattainment Area. This document specifically serves as an evaluation of the PacifiCorp Energy operated Gadsby Power Plant.

1.1 Facility Identification

Name: Gadsby Power Plant

Address: 1407 West North Temple (rear), Salt Lake City, Utah, Salt Lake County

Owner/Operator: PacifiCorp Energy

UTM coordinates: 4,513,486 m Northing, 421,582 m Easting, Zone 12

1.2 Facility Process Summary

The Gadsby Power Plant (Gadsby) is a natural gas-fired electric generating plant consisting of three (3) steam boilers (Units #1, #2 and #3) and three (3) simple-cycle combustion turbines (Units #4, #5 and #6). Unit #1 is a 65 MW unit constructed in 1951, Unit #2 is an 80 MW unit constructed in 1952, and Unit #3 is a 105 MW unit constructed in 1955. Fuel oil may be used in Units #1, #2, and #3 as a back-up fuel during natural gas curtailments. Units #1 and #2 are equipped with low NO_x burners. Units #4-6 are 43.5 MW LM6000 natural gas-fueled simple cycle combustion turbine engines that were added in 2002. The plant also has two small black start (emergency) generators (175 kW and 1,007 kW), three cooling towers for the boilers, and several small storage tanks.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

65 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #1

80 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #2

105 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #3

43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #4

43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #5

43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #6

175 kW diesel generator – Em Gen #1

1,007 kW diesel generator – Em Gen #2

Storage tanks (several tanks ranging in size from 975 gallons to 4,200 gallons)

Cooling Towers #1, #2, #3

1.4 Facility 2016 Baseline Actual Emissions and Current PTE

In 2016, Gadsby’s baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM _{2.5}	16.9
SO ₂	1.5
NO _x	117.4
VOC	9.6
NH ₃	13.2

The current PTE values for Gadsby, as established by the most recent AO issued to the source (DAQE-AN103550015-09) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM _{2.5}	114.27
SO ₂	10.1
NO _x	716.1
VOC	23.0
NH ₃	*

* No allowable emissions or PTE were ever determined for this pollutant

2.0 Modeled Emission Values

A full explanation of how the modeling inputs are determined can be found elsewhere. However, a shortened explanation is provided here for context.

The base year for all modeling was set as 2016, as this is the most recent year in which a complete annual emissions inventory was submitted from each source. Each source’s submission was then verified (QA-QC) – checking for condensable particulates, ammonia (NH₃) emissions, and calculation methodologies. Once the quality-checked 2016 inventory had been prepared, a set of projection year inventories was generated. Individual inventories were generated for each projection year: 2017, 2019, 2020, 2023, 2024, and 2026. If necessary, the first projection year, 2017, was adjusted to account for any changes in equipment between 2016 and 2017. For new equipment not previously listed or included in the source’s inventory, actual emissions were assumed to be 90% of its individual PTE.

While some sources were adjusted by “growing” the 2016 inventory by REMI growth factors; other sources were held to zero growth. This decision was largely based on source type, and how each source type operates. Utility sources, for example, are not likely to experience a growth in sales or related production. They operate based on large-scale power demand and the needs of the power grid.

For Gadsby, a summary of the modified emission totals for 2017 are shown below in Table 3. Since a value of zero (0) growth was applied at the utility sources, these same values would then propagate through for each of the subsequent projection years.

Table 3: Modeled Emission Values (Plant-Wide)

Pollutant	2017 Projected Actual Emissions (Tons/Year)
PM _{2.5}	16.9
SO ₂	1.5
NO _x	117.4
VOC	9.6
NH ₃	13.2

Finally, the effects of BACT were then applied during the appropriate projection year. Any controls applied between 2016 and 2017 (such as any RACT or RACM required as a result of the moderate PM_{2.5} SIP), was previously taken into account during the 2017 adjustment performed earlier. Future BACT, meaning those items expected to be coming online between today and the regulatory attainment date (December 31, 2019), would be applied during the 2019 projection year. Notations in the appropriate table of emission inventory model input spreadsheet indicate the changes made and the source of those changes. Similarly, Additional Feasible Measures (AFM) or Most Stringent Measures (MSM), which might be applied in future projection years beyond 2019 are similarly marked on the spreadsheet. The effects of those controls are applied on the projection year subsequent to the installation of each control – e.g. controls coming online in 2021 would be applied in the 2023 projection year, while controls installed in 2023 would be shown only in 2024.

3.0 BACT Selection Methodology

The general procedure for identifying and selecting BACT is through use of a process commonly referred to as the “top-down” BACT analysis. The top-down process consists of five steps which consecutively identify control measures, and gradually eliminate less effective or infeasible options until only the best option remains. This process is performed for each emission unit and each pollutant of concern. The five steps are as follows:

1. Identify All Existing and Potential Emission Control Technologies: UDAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to: federal regulations, Utah regulations, regulations of other states, the RBLC, recently issued permits, and emission unit vendors.
2. Eliminate Technically Infeasible Options: Any control options determined to be technically infeasible are eliminated in this step. This includes eliminating those options with physical or technological problems that cannot be overcome, as well as eliminating those options that cannot be installed in the projected attainment timeframe.
3. Evaluate Control Effectiveness of Remaining Control Technologies: The remaining control options are ranked in the third step of the BACT analysis. Combinations of various controls are also included.
4. Evaluate Most Effective Controls and Document Results: The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked options. This evaluation includes energy, environmental, and economic impacts of the control option.

5. Selection of BACT: The fifth step in the BACT analysis selects the “best” option. This step also includes the necessary justification to support the UDAQ’s decision.

Should a particular step reduce the available options to zero (0), no additional analysis is required. Similarly, if the most effective control option is already installed, no further analysis is needed.

4.0 BACT for the Natural Gas-fired Boilers

The three natural gas-fired boilers are designated as Units #1, #2 and #3. Unit #1 is a 726 MMBtu/hr utility boiler equipped with low-NO_x burners (LNB). Constructed in 1951, it powers a 65 MW generator. Unit #2 is a 825 MMBtu/hr boiler constructed in 1952. Also equipped with LNB, it powers a 80 MW generator. Unit #3 is a 1,155 MMBtu/hr boiler using a flue-gas recovery system for NO_x emissions control. The boiler was constructed in 1955 and powers a 105 MW generator.

All three units are primarily fired on pipeline quality natural gas; however, diesel fuel may be used during periods of natural gas curtailments and for maintenance firings. Maintenance firings may not exceed one percent (1%) of the total annual heat input to the boilers.

Following the emissions correction procedure outlined in Section 2.0 above, the 2014 baseline emissions for the three boilers were calculated as follows:

PM_{2.5} = 10.27 tons
SO₂ = 0.99 tons
NO_x = 102.39 tons
VOC = 7.43 tons
NH₃ = 4.32 tons

4.1 PM_{2.5}

4.1.1 Available Control Technology

Controls for particulate emissions fall into one of three groups: pre-combustion controls, which seek to eliminate contaminants in the inlet air prior to the boiler; combustion controls, such as specific burners or combustion design; and post-combustion controls, such as electrostatic precipitators or baghouses.

The identified controls are as follows:

Inlet air filters: primarily used to filter out small particulate matter in the inlet air. These filters are not particularly useful on utility boilers. While they can provide some aid in reducing plugging and associated wear on the LNB; utility boilers, especially those fired on natural gas, are fired at or near atmospheric pressure with relatively low inlet gas velocities. Typically, burner plugging and other wear/damage is related to fuel contaminants, and not to the combustion air – unless the combustion air is particularly particulate-laden. The chance of burner plugging, or other damage to internal components is essentially zero in this circumstance.

Good combustion practice: this is nothing but properly operating the boilers with the correct ratio of air to fuel in order to maximize combustion and minimize unburned fuel.

Clean burning fuels: includes the use of inherently low emitting fuels like natural gas.

Specific burner and/or combustion chamber design: the more efficiently a boiler is able to operate, the less pollution it will generate for a given amount of fuel combusted. Primarily this includes low-NO_x burners, ultra-low-NO_x burners, and staged fuel combustion with overfire air injection. For particulate control in natural gas combustion, there is little to no difference between the various burner designs or configurations as the degree of complete combustion is the ultimate deciding factor in particulate control.

Add-on particulate controls: this final option includes traditional “add-on” control systems such as baghouses or electrostatic precipitators. These types of controls would be installed in the exhaust gas stream exiting the boiler combustion chamber, but prior to the emissions exiting the stack.

4.1.2 Evaluation of Technical Feasibility of Available Controls

With the low risk of damage to the boilers by firing exclusively on pipeline quality natural gas, the use of inlet particulate filters is not technically feasible. While some filtration of inlet air would occur, these filters would result in essentially zero reduction in particulate emissions given the low inlet flow rates to the boilers. Additional ductwork, fans and control equipment would also be required.

The use of clean burning fuels, good combustion controls, and proper burner design are all technically feasible.

The use of add-on post-combustion particulate controls – such as baghouse filtration, scrubbers, or ESPs – is not technically feasible. Given the low concentration of particulate matter in the exhaust stream, and the generally low levels of particulate matter being generated from natural gas combustion, add-on controls are simply not effective or available, even for larger utility boilers of these size ratings. Add-on controls are designed primarily to control the filterable fraction of particulate emissions, and do very little to control the condensable fraction.

The 2016 actual emissions of particulate totaled just 10.27 tons. Even if all three boilers had been operated for the full 8,760 hours allowed under the existing permit, the maximum amount of particulate emissions would still have totaled only 31.13 tons. In natural gas combustion, 75% of the particulate emissions are of the condensable fraction, leaving just 2.57 tons (7.78 tons under maximum possible output) of post-combustion-controllable emissions. No control systems are commercially available for controlling these levels of emissions for large utility boilers.

4.1.3 Evaluation and Ranking of Technically Feasible Controls

The three utility boilers have all the remaining control options (good combustion practices, proper burner design, and clean burning fuel) as existing controls. There is no need to rank these controls on control effectiveness, as all three control systems can be used simultaneously. Since the choice of burner design (standard burner vs LNB vs ULNB, for example, see the section on NO_x control for details) makes little difference in controlling particulate emissions; specific burner type will not be discussed here.

4.1.4 Further Evaluation of Most Effective Controls

Further evaluation of the existing controls is not required. All technically available control options are in place and operational on the utility boilers at the Gadsby Plant.

4.1.5 Selection of BACT/BACM

Retention of the existing particulate controls should remain as BACM. There are no specific PM_{2.5} emission limitations on any of the utility boilers. As the control techniques are primarily work practices or are inherent in the design of the boiler, they are considered BACM rather than BACT. Therefore, inclusion of a specific emission limitation is not necessary.

4.2 NO_x

NO_x, or oxides of nitrogen, are formed from the combustion of fuel in a boiler's firebox. There are three mechanisms for the formation of NO_x: fuel NO_x, which is the oxidation of the nitrogen bound in the fuel; thermal NO_x, or the oxidation of the nitrogen (N₂) present in the combustion air itself; and prompt NO_x, which is formed from the combination of combustion air nitrogen (N₂) with various partially-combusted intermediary products derived from the fuel. For combustion within the utility boilers, thermal NO_x is the major contributor. Prompt NO_x contributes slightly only in the initial stages of combustion, and fuel NO_x is only a contributor during combustion of fuel oil (natural gas is inherently low in nitrogen content). All three processes are temperature dependent – combustion temperatures below 2700°F greatly inhibit NO_x formation.

4.2.1 Available Controls

For control of NO_x emissions from the utility boilers there are both pre- and post-combustion options available. Beside the two inherent options of clean burning fuels and good combustion practices, there are five different combustion techniques: low-NO_x burners, ultra-low-NO_x burners with internal flue gas recirculation, staged air/fuel combustion (aka overfire air injection), low excess air firing, and external flue gas recirculation. The source also identified three post-combustion controls, specifically: SNCR, SCR, and EM_xTM. UDAQ also identified four other options: Xonon Cool Combustion®, LoTO_xTM, PahlmannTM, and NO_xOUTTM, as available control options that could be applied to the utility boilers.

Combustion techniques:

Clean Burning Fuels: The use of natural gas rather than fuel oil or coal is the most commonly cited example of using clean burning fuels. This is the default case for all three of the utility boilers at the Gadsby plant.

Good Combustion Practices: This is nothing more than proper operation of the boilers to minimize emissions, minimize fuel use, and maximize power generation. It includes regular maintenance as well as periodic testing and monitoring. This is also part of the default case at the Gadsby plant.

Low-NO_x Burners (LNB): Typically thought of as an advanced version of a standard burner, the LNB reduces NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two main types of LNB: staged fuel and staged air burners. Staged fuel burners divide the combustion zone into two regions, limiting the amount of fuel supplied in the first zone with the standard amount of combustion air, and then supplying the remainder of the

fuel in the second zone to combust with the un-combusted oxygen from the first zone. Staged air burners reverse this, limiting the combustion air in the first zone then supplying the remainder of the combustion air in the second zone to combust the remaining fuel. Staged fuel LNBS are more suited to natural gas-fired boilers as they are designed to restrict flame temperature.

Ultra-Low-NO_x Burners (ULNB): Most commonly a combination of LNB technology with some internal flue gas recirculation. The burner recirculates some of the hot flue gases from the flame or firebox back into the combustion zone. Since these high temperature flue gases are oxygen depleted, the burner lowers the speed at which fuel can be combusted without reducing the flame temperature below the level needed for optimum combustion efficiency. Reducing oxygen concentrations in the firebox most directly impacts fuel NO_x generation.

Flue Gas Recirculation (FGR): External FGR involves recycling of flue gas back into the firebox as part of the fuel-air mixture at the burner. Although similar to the concept of ULNB, rather than using burner design features to recirculate gases from within the firebox, FGR uses external ductwork to route a portion of the exhaust stream back to the inlet side of the boiler and return it into the boiler windbox.

Xonon Cool Combustion®: Catalytica Energy Systems' Xonon Cool Combustion® System is a specific type of catalytic combustion process, and often mentioned independently in control technology reviews. In practical application, however, it functions similarly to other catalytic combustors. These combustors use a flameless catalytic combustion module to initiate the combustion process, followed by a more traditional combustion process downstream of the catalyst. This two-stage process lowers the overall combustion temperature.

Staged Air/Fuel Combustion (Over-fire Air Injection): Over-fire air (OFA) is a combustion staging practice typically used in combination with LNB, but not with ULNB or FGR. In OFA designs, a portion of the combustion air is injected separately from the LNBS to a higher elevation in the firebox. This lowers the flame temperature by reducing the oxygen concentration in the area of the firebox where the fuel is being injected. This oxygen-reduced section would then be followed by the second "over-fire air" section that would act as an oxidation zone to complete combustion. This splits the firebox into two zones in the same way as the staged-air LNB.

Low Excess Air Firing: One factor that might influence the formation of NO_x is the amount of excess combustion air. The additional oxygen and nitrogen present in the excess combustion air can combine and form thermal NO_x. Limiting excess air can be accomplished with proper burner design and through oxygen trim controls.

Post Combustion Controls:

Selective Catalytic Reduction (SCR): In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into a boiler's exhaust; just past the firebox (sometimes within the upper stages of the firebox), and upstream of a metal or ceramic catalyst. As the exhaust gas/reducing agent mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range (typically between 480°F and 800°F with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the

upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate or honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

Selective Non-catalytic Reduction (SNCR): Very similar to SCR, only without the use of a catalyst bed. SNCR simply uses the application of ammonia or (more commonly in this case) urea to achieve NO_x control. And rather than injection into the exhaust stream, the reducing agent is usually injected directly into the upper end of the firebox. This lowers the flame temperature and helps to ensure adequate mixing of the exhaust gases and the reducing agent. Fuel Tech's NO_xOUT™ process is a subset of SNCR designed to operate at higher temperatures by using stabilized urea liquor injected directly into the firebox.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without the need of a reagent such as ammonia. The NO emissions are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO₂ from the catalyst and reduce it to N₂ prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO₂ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

Linde's LoTOx™ technology uses ozone injection to oxidize NO and NO₂ to N₂O which is highly soluble and easier to remove through the use of another control device such as a wet scrubber. UDAQ has seen and permitted the application of this technology in combination with a wet gas scrubber for emission control at a petroleum refinery.

Enviroscrub's Pahlmann™ Process is a sorbent-based control system which functions similarly to a dry scrubber. In this system, Pahlmanite (a manganese dioxide sorbent) is injected into the exhaust stream for NO_x removal and then collected in a particulate control device like a baghouse. The sorbent is then regenerated in an aqueous process, filtered and dried, and is then ready for reinjection. The wastewater is sent offsite for disposal.

4.2.2 Evaluation of Technical Feasibility of Available Controls

Both default case options of clean burning fuels and good combustion practices are technically feasible. The Gadsby plant has been using pipeline quality natural gas as the primary fuel. While some use of fuel oil is allowed for natural gas curtailments and maintenance firings, the amount of fuel oil used cannot exceed 1% of the total heat input to the boilers. Good combustion practices are a standard requirement of UDAQ's NSR permits.

Of the available combustion techniques, only Xonon® is not technically feasible. The Xonon combustor is specifically designed for use in combustion turbines and not for industrial boilers. The current owner of the technology, Catalytica Energy Systems, is only marketing Xonon

technology for gas turbines within the 1 to 15 MW size range. At this time, there is no information available on the transferability of the technology to other combustion processes.

Most of the post-combustion controls that have been identified are technically feasible. Generally, these controls are widely used and have been demonstrated to control NO_x emissions from industrial and utility boilers. Only EMx™, LoTOx™, and Pahlmann™ have any technical feasibility concerns.

The EMx™ system has not been demonstrated in practice on large industrial boilers. The catalyst system operates best in a gas temperature range of 500-700°F, well above the expected 250°F exhaust temperature of the three boilers. LoTOx™ still requires the use of another pollutant control system such as a wet gas scrubber to remove the N₂O. This other control imposes additional infrastructure for little additional pollutant removal. The Pahlmann™ system also requires the addition of a baghouse or other particulate control system, an aqueous sorbent regeneration system, and wastewater treatment and disposal. The system has not been demonstrated in practice on natural gas-fired equipment, especially on industrial boilers.

Given these concerns, Xonon®, EMx™, LoTOx™, and Pahlmann™ were all eliminated from further consideration. All other identified control options (combustion technique or post-combustion controls) remain as technically feasible options.

4.2.3 Evaluation and Ranking of Technically Feasible Controls

For the remaining control options the following table shows the expected ranking and degree of emission control:

Table 4-1: NO_x Control Options

Control Technology	Rate of Control
ULNB + SCR	85-99%
LNB + SCR	85-95%
ULNB + SNCR	80-90%
SCR	80-90%
LNB + SNCR	55-75%
ULNB	50-80%
LNB + FGR	55-75%
LNB	35-55%
SNCR	30-50%
FGR	30-50%
Low excess air	5-10%

The top control option identified is ULNB in conjunction with SCR. A review of recent permitting actions for large industrial and utility boilers with input rates greater than 250 MMBtu/hr fired only on natural gas or fuel oil yielded limited results. The lowest emission limits found were for utility boilers permitted in 2014 and 2015 using either LNB with SCR or ULNB alone. No recently permitted large boilers were found using both ULNB and SCR in combination – even though this appears to be the most effective control mechanism.

One combination not listed in the table above was the use of ULNB and FGR; likely because this makes use of redundant control technology. The combination is listed twice in Table 4-3 on page

4-11 of the PacifiCorp Gadsby BACT Determination document, but was not mentioned further in the source’s analysis. Both control techniques rely on some degree of recirculation of the flue gases to reduce the oxygen concentration in the inlet air stream. Combining the two processes would lessen the benefits each would provide if used individually, such that they would work antagonistically rather than synergistically. UDAQ investigated each listing individually to identify the “use” of both ULNB and FGR. For the Indiana Gasification Plant in Rockport, IN (with a listed NO_x emission rate of 0.0123 lb/MMBtu on a 24-hr basis), UDAQ retrieved the original BACT analysis. Rather than showing that both technologies had been installed, the permit reviewer was expressing that the ULNB being installed used FGR – as in “ULNB = LNB+FGR”. Only ULNB were ever installed, and the entry on the RBLC was merely in error. For the ADM Corn Processing Plant in Cedar Rapids, Iowa (with a listed emission rate of 0.02 lb/MMBtu on a 30-day rolling average), the situation was similar. After finding the original engineering review, UDAQ was able to learn that the BACT determination was for LNB with FGR, and that the RBLC entry for this permit was also in error. The use of ULNB+FGR will not be evaluated further.

4.2.4 Further Evaluation of Most Effective Controls

There are few energy related impacts with installation or operation of SCR or SNCR. There are no energy or environmental impacts associated with the potential installation of FGR on Boilers #1 or #2 or the potential installation of LNB on Boiler #3. One potential source of concern with operation of either SCR or SNCR is the generation of ammonia slip. Unreacted ammonia, meaning any ammonia which does not react with the NO_x present in the exhaust stream, may react with HCl to form ammonium chloride, or with SO₃ to form ammonium sulfate/sulfite. This can occur either in the exhaust stream or in the ambient air. The unreacted ammonia is referred to as “ammonia slip.” Ammonia slip itself often requires permit limitations as a precursor pollutant.

PacifiCorp provided cost effectiveness calculations for installation of additional control systems on each of the three boilers at Gadsby based on the existing equipment already in place. For example, as Units #1 and #2 already have LNB installed, that option was only evaluated at Unit #3. Similarly Unit #3 already operates with FGR and would not need to have that option re-evaluated. The following table summarizes the information provided by the source:

Table 4-2: Cost Effectiveness of Technically Feasible Controls by Boiler

Boiler	Control	Annualized Cost	NO _x Reduction (TPY)*	Cost Effectiveness (\$/ton)
Unit #1	SCR	\$2,831,487	79.18	\$35,761
Unit #1	SNCR	\$831,415	16.22	\$51,267
Unit #1	FGR	\$258,036	19.08	\$13,524
Unit #2	SCR	\$3,254,754	89.98	\$36,174
Unit #2	SNCR	\$893,186	18.43	\$48,467
Unit #2	FGR	\$317,583	21.68	\$14,648
Unit #3	SCR	\$4,199,066	101.18	\$41,502
Unit #3	SNCR	\$1,062,143	12.65	\$83,982
Unit #3	LNB	\$1,246,674	43.72	\$28,512

*Values listed are in PTE

Unfortunately the values provided by the source do not provide all of the necessary information, as the analysis it performed was using reductions in potential emissions, rather than actual emissions. Here is the same information, with the last two columns adjusted. In order to

calculate the “best” cost effectiveness, the highest control value from Table 4-1 was used for each control option. The reduction in actual emissions was calculated using the values based on the 2017 projection year information:

Table 4-3: Corrected Cost Effectiveness of Technically Feasible Controls by Boiler

Boiler	Control	Annualized Cost	NO _x Reduction (TPY) (Actuals)	Cost Effectiveness (\$/ton)
Unit #1	SCR	\$2,831,487	12.93	\$219,070
Unit #1	SNCR	\$831,415	7.18	\$115,787
Unit #1	FGR	\$258,036	7.18	\$35,935
Unit #2	SCR	\$3,254,754	15.24	\$213,625
Unit #2	SNCR	\$893,186	8.46	\$105,524
Unit #2	FGR	\$317,583	8.46	\$37,520
Unit #3	SCR	\$4,199,066	63.99	\$65,618
Unit #3	SNCR	\$1,062,143	39.11	\$31,879
Unit #3	LNB	\$1,246,674	35.55	\$29,876

When corrected, the value of each control becomes less effective as actual emissions drop. Unit #1, which was operated least often by the source, shows the lowest amount of reductions in actual emissions and thus has the highest \$/ton cost effectiveness values.

Currently the Gadsby plant boilers operate at approximately a 25% capacity factor. Individual limits are as follows:

Unit 1: 336 ppmvd @ 3% O₂, 179 lb/hr (approx. 0.25 lb/MMBtu)

Unit 2: 336 ppmvd @ 3% O₂, 204 lb/hr (approx. 0.25 lb/MMBtu)

Unit 3: 168 ppmvd @ 3% O₂, seasonal limits of 142 lb/hr (approx. 0.12 lb/MMBtu) from 11/1 through 2/28(29) and 203 lb/hr (approx. 0.18 lb/MMBtu) from 3/1 through 10/31.

Installation of either SCR or SNCR does not appear to be cost effective for any of the three boilers. The lowest \$/ton value is calculated for Unit #3 at nearly \$32K per ton of NO_x removed. Although BACT economic infeasibility ranges vary from location to location, the most expansive of these (San Joaquin Valley Air Pollution Control District – SJVAPCD), tops out at \$25K/ton.

Similarly, the installation of FGR on Units #1 and #2 or the application of LNB on Unit #3 are equally economically infeasible.

4.2.5 Selection of BACT/BACM

Currently, BACT for NO_x control at the three utility boilers is the use of the existing control systems. The use of natural gas and good combustion controls on all three units. Units #1 and #2 will remain equipped with LNB rated at approximately 0.25 lb/MMBtu. Unit #3 will remain equipped with FGR. The existing emission limits of:

1. Gadsby 1 boiler stack

Pollutant	Lbs/hr	ppmdv (3% O ₂ , dry)
NO _x	179.00	336

2. Gadsby 2 boiler stack

Pollutant	Lbs/hr	ppmdv (3% O ₂ , dry)
NO _x	204.00	336

3. Gadsby 3 boiler stack

	a. Winter (November 1 through February 28/29):	
Pollutant	Lbs/hr	ppmdv (3% O ₂ , dry)
NO _x	142.00	168

	b. Summer (March 1 through October 31):	
Pollutant	Lbs/hr	ppmdv (3% O ₂ , dry)
NO _x	203.00	168

shall remain in place as BACT limits.

Additional Feasible Measures (AFM) and Most Stringent Measures (MSM) will be discussed in a separate section.

4.3 VOC

As with any combustion source, VOC emissions in boilers are the result of unburned hydrocarbons formed during incomplete combustion. The formation of VOCs is dependent on combustion system design, choice of fuel, combustion temperature, and operating practices.

4.3.1 Available Control Technology

The available control techniques for VOC emissions can be sorted into three categories: pre-combustion controls, thermal oxidation and oxidation catalysts.

Pre-combustion controls include those items such as equipment design (proper burners), good combustion practices, the use of pipeline quality natural gas as fuel, maintaining high combustion efficiencies, maintaining proper air-to-fuel ratios, and conducting proper maintenance. These items have all been previously discussed under the particulate and NO_x control sections (4.1.1 and 4.2.1) above.

Thermal oxidation is the use of a secondary combustion process to burn off the remaining unburned VOCs (oxidize) into CO₂ and water vapor. This process also oxidizes CO as a secondary benefit. The oxidation process typically requires a separate combustion chamber, burner, and heat exchanger; and in some cases, additional fuel input.

Most oxidation catalysts are designed to control both VOCs and CO. The exhaust gas stream is sent through the catalyst “bed”, which consists of a honeycomb shaped substrate material that is coated with the catalyst. The gas stream needs to be relatively particulate-free to prevent fouling of the catalyst. Oxidation catalysts do not use additional reagent chemicals like SCR systems.

One specific oxidation catalyst, EMx™, has been used to oxidize and remove both NO_x and VOC. The system uses a platinum-based catalyst coated with potassium carbonate (K₂CO₃) – see the section on NO_x control, Section 4.2, for additional information.

4.3.2 Evaluation of Technical Feasibility of Available Controls

Combustion controls, proper design and operation, are the most common means of controlling VOC emissions from large industrial boilers. Controlling VOC emissions through operational and design elements is far easier and cost efficient than the application of add-on control

techniques.

Although available, no applications of thermal oxidation have been applied to industrial boilers of the size found at the Gadsby plant. Thermal oxidation requires a higher concentration of VOCs and CO than is typically present in industrial boiler exhaust. The average exhaust gas temperature of 200-250°F is quite low and would require a high degree of supplemental heat input to be added in the thermal combustor to raise the exhaust gas above the thermal oxidation temperature of 1500°F. No examples were identified of application of thermal oxidizers to boilers similar to those at Gadsby.

Oxidation catalysts have been employed on similarly sized industrial boilers in several locations and are considered both commercially and technically feasible.

Therefore, pre-combustion controls and oxidation catalysts will be evaluated further as BACT.

4.3.3 Evaluation and Ranking of Technically Feasible Controls

Good combustion practices for the utility boilers are the continued use of pipeline quality natural gas as fuel, adjustment of combustion flame temperature and combustion residence time, proper fuel-air mixing and adequate turbulence in the flue gas. As none of these practices are contradictory, there is no need to rank these controls. All can be performed in concert and will be viewed as single control option; “combustion controls.” Oxidation catalysts can be used in addition to combustion controls. Oxidation catalysts treat the exhaust gas stream and have little effect on the combustion process aside from some adjustment to account for the pressure drop. Since all remaining controls can be used simultaneously the only remaining evaluation is whether the cost benefit analysis justifies the application of each control method.

The three boilers at Gadsby already utilize combustion controls. With well-designed burners, proper fuel air mixing, and computerized feedback controls, the boilers at the Gadsby plant are continually adjusted to maintain optimum combustion. As these control options are already in use, no economic analysis is necessary. The source submitted an economic analysis for installation of an oxidation catalyst on each of the three boilers. The analysis was based on an average VOC reduction efficiency of 30%. The following table summarizes the analysis.

Table 4-4: Economic Analysis of Oxidation Catalyst Installation on Boilers #1-#3

Unit	Annualized Cost	Tons/Year VOC Removed	\$/Ton Cost Effectiveness
#1	\$2,042,328.00	0.25	\$8,169,312.00
#2	\$2,218,327.00	0.31	\$7,155,893.55
#3	\$2,428,785.00	1.66	\$1,463,123.49

As with the NO_x analysis, the values submitted by the source were based on potential to emit, rather than the adjusted 2017 actual emissions. The values listed in Table 4-4 above have been corrected to use the 2017 actual emissions. The adjustment calculations can be found on the emission calculation spreadsheet.

4.3.4 Further Evaluation of Most Effective Controls

Based on the economic analysis provided by the source, the use of an oxidation catalyst is not feasible for the Gadsby utility boilers. The remaining combustion controls are already installed and in use on the boilers. No additional evaluation is required.

4.3.5 Selection of BACT

Retention of the existing control systems (good combustion practices and proper equipment design) for control of VOC emissions is recommended as BACT. There are no existing VOC limitations in the PM_{2.5} moderate SIP for the utility boilers. It is recommended that this remain the case in the PM_{2.5} serious SIP as no specific control equipment is being installed that requires monitoring. Good combustion practices can remain a condition of the AO and Title V permits without requiring SIP-level monitoring, given the low level of VOC emissions expected from the three utility boilers.

4.4 SO₂

Sulfur dioxide emissions from combustion are directly related to the amount of sulfur present in the fuel. The utility boilers are primarily fired on pipeline-quality natural gas, which is inherently low in sulfur. The use of fuel oil is permitted only during periods of natural gas curtailment and during maintenance firings. The total heat input from fuel oil cannot exceed one (1) percent of the annual heat input to the boilers.

4.4.1 Available Control Technology

To reduce SO₂ emissions, a source can either reduce the amount of sulfur present in the fuel or apply post-combustion controls such as flue gas desulfurization. The use of pipeline quality natural gas is considered a control technique for fuel-sulfur minimization. The analysis by the source provided no additional controls related to fuel switching during periods of fuel oil firing, even with an estimated fuel-oil sulfur content of 0.45% by weight. Lower sulfur content fuel oils do exist and are commonly in use. Therefore, fuel oil switching could have potentially been evaluated as an “available” technique.

However, as provided in the most recent NSR permit issued to the source (which was issued in 2009), the fuel oil allowed for combustion in the boilers must be #2 or better. By definition, #2 fuel oil (or diesel fuel) is now ultra-low sulfur diesel as of December 1, 2014. The fuel standard is found in 40 CFR 60.4207 (40 CFR 80.510 incorporated by reference). Ultra-low sulfur diesel (ULSD) is 15 ppm sulfur, or 0.0015% by weight, much lower than the 0.45% listed above. The source has not operated on fuel oil in over 30 years, but would be required to use ULSD if it were to do so in the future. So while the source may not have evaluated fuel switching for periods of fuel oil combustion, it will happen automatically.

As for post-combustion controls, primarily only flue gas desulfurization systems exist. These are wet or dry scrubbing systems which remove SO₂ through absorption with a scrubbing reagent. Wet scrubbers typically mix the reagent with water and use one of a variety of contacting chambers or “towers” to allow the exhaust stream and scrubbing liquid to contact. Dry scrubbers use dry injection, spray drying or a combination of the two to inject the scrubbing reagent (typically a lime-slurry) directly into the exhaust stream. The reacted slurry is then removed in a particulate control device.

4.4.2 Evaluation of Technical Feasibility of Available Controls

No post-combustion SO₂ controls have been found to be technically feasible for use on natural gas fired boilers of this size or type. The SO₂ concentrations are considered too low for scrubbing technologies to be effective. The extra pressure drop associated with the scrubbing system and added particulate capture system (typically a baghouse), plus the cost of the scrubber and

baghouse have led to these systems not being applied in practice and they are not considered commercially available for natural gas-fired utility boilers.

The use of low sulfur fuels, such as natural gas and ULSD, is considered technically feasible and is already in use at Gadsby.

4.4.3 Evaluation and Ranking of Technically Feasible Controls

With the elimination of all post-combustion SO₂ controls, there is no need to rank the single remaining control of fuel sulfur limiting. The use of inherently low-sulfur fuels such as pipeline-quality natural gas and ULSD is the only technically viable control option. It is also the existing base-case already in use at the Gadsby plant.

4.4.4 Further Evaluation of Most Effective Controls

The source provided a cost analysis of installing and operating either type of flue gas desulfurization system, under the assumption that this type of system could be employed during periods of fuel oil combustion to reduce SO₂ emissions when using a higher sulfur fuel. The calculations were based on the maximum allowed fuel oil content listed in the NSR permit issued to the source (0.45% by weight), and the assumption that the maximum amount of fuel oil allowed would be burned each year (1% of maximum heat input). Under these assumptions, the source could potentially emit an additional 14 tons of SO₂ and the use of a wet or dry gas scrubber could remove as much as 12.6 tons of this additional SO₂.

However, the assumptions used by the source did not take the revised fuel sulfur content limitation of ULSD into account. By burning only ULSD, the Gadsby plant could only produce an additional 0.05 tons of SO₂. Even assuming the same removal efficiency of >89%, the use of a flue gas scrubber would only result in 0.04 tons of SO₂ being removed.

PacifiCorp's cost and efficiency estimates resulted in a best case cost effectiveness of \$2.7M/ton SO₂ removed. Using the revised emission values listed above, the cost effectiveness would change to \$850.5M/ton SO₂ removed. This is further proof that scrubbing systems are not effective for natural gas-fired boilers.

4.4.5 Selection of BACT/BACM

The use of low sulfur fuels such as pipeline-quality natural gas and ULSD are the only feasible SO₂ control technologies for the utility boilers and are considered BACM. There are no specific SO₂ emission limitations on the utility boilers in the NSR permit or the PM_{2.5} moderate SIP. It is recommended that this remain the case in the serious SIP as there is no control equipment necessary to artificially restrict SO₂ emissions. UDAQ recommends bringing forward the existing requirement on the total heat input of fuel oil allowed within a given annual period, and including a definitive statement that only ULSD is allowed as the alternate fuel.

5.0 BACT for the Combustion Turbines

There are three LM6000 combustion turbines (CTs), identified as Units #4, #5 and #6. Each is operated as a simple-cycle unit fired exclusively on pipeline quality natural gas. The CT provides primary power generation by spinning a generator directly. As simple cycle units, the turbines do not have heat recovery steam generators (HRSGs), nor any form of duct firing (supplemental fuel-firing to the HRSG boilers).

Following the emissions correction procedure outlined above in Section 2.0, emissions from the three CTs are as follows:

PM_{2.5} = 6.55 tons
SO₂ = 0.49 tons
NO_x = 14.47 tons
VOC = 2.08 tons
NH₃ = 8.82 tons

The calculations are shown on the projection emission spreadsheet.

5.1 PM_{2.5}

5.1.1 Available Control Technology

Controls for particulate emissions fall into one of three groups: pre-combustion controls, which seek to eliminate contaminants in the inlet air prior to the combustion chamber; combustion controls, such as specific burners or combustion design; and post-combustion controls, such as electrostatic precipitators or baghouses.

The identified controls are as follows:

Inlet air filters: primarily used to filter out small particulate matter in the inlet air to protect the combustion turbine. These filters can be static or self-cleaning, with the self-cleaning type requiring less maintenance.

Good combustion practice: this is nothing but properly operating the combustion turbines with the correct ratio of air to fuel in order to maximize combustion and minimize unburned fuel.

Clean burning fuels: includes the use of inherently low emitting fuels like natural gas.

Specific burner and/or combustion chamber design: the more efficiently a turbine is able to operate, the less pollution it will generate for a given amount of fuel combusted (or, to be more precise); as less fuel will be required to generate the same amount of power. This option includes both the use of high efficiency turbines, as well as inherently lower emitting burners such as dry low-NO_x (DLN) combustors.

Add-on particulate controls: this final option includes traditional “add-on” control systems such as baghouses or electrostatic precipitators. These types of controls would be installed post combustion, and prior to the emissions exiting the stack.

5.1.2 Evaluation of Technical Feasibility of Available Controls

Post-combustion particulate controls such as baghouses and electrostatic precipitators have not been demonstrated in practice for use on combustion turbines. There are multiple factors that combine to eliminate these types of controls from consideration. 1) Combustion turbine particulate emissions have a small aerodynamic diameter – typically on the order of 1 micron or less – which makes the use of most direct physical capture systems problematic. 2) Natural gas-fired turbines generate little in the way of particulate emissions; yet also have high volume exhaust flows. This combination results in a low concentration of PM in the exhaust. 3) Post-

combustion controls have difficulty operating efficiently or effectively in low concentration environments. Baghouse-style filtration systems rely on the buildup of a filter cake of captured particulates to enhance capture efficiency, while scrubbing systems require a reasonable particulate concentration in order to operate efficiently. Electrostatic precipitators can operate in low concentration conditions, but also suffer efficiency problems. In addition, a search was conducted for the use of ESPs with natural gas-fired turbines and no results were found. A single article which discussed a bench-scale experiment was found, but no commercially available operations were located in the results. The UDAQ was unable to identify any combustion turbines fired on gaseous fuels using post combustion controls for the control of particulate emissions. Post-combustion controls are therefore considered technically infeasible and removed from additional consideration.

All of the remaining control options are considered technically feasible and require additional evaluation.

5.1.3 Evaluation and Ranking of Technically Feasible Controls

The remaining control options under consideration are not mutually exclusive. A single high-efficiency combustion turbine can be operated with inlet air filters and using good combustion practices. The turbine can be fired exclusively on natural gas as the sole fuel source, and use a well-designed burner system. Thus, the remaining controls do not need to be ranked – rather they should be combined and considered as a group. When combined, this group can be treated as a single control option – “good combustion practices” – and no further evaluation under step 3 is required.

5.1.4 Further Evaluation of Most Effective Controls

All three combustion turbines at this facility are already using good combustion practices. No adverse economic, environmental or energy costs will result.

5.1.5 Selection of BACT controls

The Gadsby plant is already employing inlet air filters, properly designed combustors, and pipeline quality natural gas as fuel as BACT control options. Utah rules R307-401-4(1) & (2) require that all sources maintain and operate any equipment, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions (good combustion practices). Thus, each of the identified control options is already in place and operating at the facility.

The most recently issued NSR permit for the Gadsby plant does not contain any limits on direct emissions of $PM_{2.5}$. Similarly, no $PM_{2.5}$ limits were set in the moderate $PM_{2.5}$ SIP either. Therefore, UDAQ recommends that the existing controls be accepted as BACM for control of particulate emissions from the combustion turbines.

5.2 SO₂

Emissions of SO_2 (and H_2SO_4 as well) are directly a function of the amount of sulfur present in the fuel. As the fuel is burned, the fuel-bound sulfur is oxidized to SO_2 (some H_2SO_4 is also formed).

5.2.1 Available Control Technology

Most sulfur control technologies require the use of some sort of acid reducing agent such as a lime slurry or limestone injection. This leads to residual solid or liquid waste which requires subsequent disposal. The remaining add-on control techniques rely on the post-combustion control of emissions of particulates and allowing any residual sulfur to be captured with the particulate.

Rather than relying on post-combustion controls, an alternative option would be to reduce the amount of sulfur present in the fuel, thus eliminating the source of the SO₂. The use of low sulfur fuels, primarily the use of pipeline-quality natural gas, is the most common method of controlling SO₂ emissions from CTs. This also happens to be the base case at the Gadsby plant.

5.2.2 Evaluation of Technical Feasibility of Available Controls

Neither of the possible post-combustion/add-on control options is technically feasible. With all of the combustion turbines being fired on natural gas, the amount of fuel-bound sulfur is inherently quite low. UDAQ has been unable to locate any technologies to further reduce the amount of sulfur present in pipeline quality natural gas.

Post-combustion desulfurization systems, such as limestone injection or dry-lime scrubbing, are typically designed for exhaust streams with much higher SO₂ (and acid gas) concentrations than those found with combustion turbines fired on natural gas. The low concentration leads to lowered control efficiencies. Effective control then requires longer residence times, longer exhaust stream runs, lowered exhaust temperatures, and worsened emission dispersal upon release.

5.2.3 Evaluation and Ranking of Technically Feasible Controls

No additional controls have been identified as being technically feasible, beyond the existing baseline control of burning only pipeline quality natural gas. Therefore, no evaluation or ranking is possible. The existing control option remains the only viable option.

5.2.4 Further Evaluation of Most Effective Controls

As no additional controls have been determined to be technically feasible, no evaluation of economics, energy consumption or adverse environmental impacts is possible.

5.2.5 Selection of BACT

No additional controls or control techniques are required. Combustion of pipeline quality natural gas as fuel for control of SO₂ emissions is recommended as BACT.

Given the relatively small amount of SO₂ estimated to be coming from the CTs (0.49 tons/year combined), no limits have been set for these units. The use of only pipeline quality natural gas as fuel represents a work practice standard rather than a measureable quantity restriction (such as a production limit) or other quantifiable limitation (such as an emission limitation).

5.3 NO_x

NO_x, or oxides of nitrogen, are formed from the combustion of fuel in the turbine. There are

three mechanisms for the formation of NO_x: fuel NO_x, which is the oxidation of the nitrogen bound in the fuel; thermal NO_x, or the oxidation of the nitrogen (N₂) present in the combustion air itself; and prompt NO_x, which is formed from the combination of combustion air nitrogen (N₂) with various partially-combusted intermediary products derived from the fuel. For combustion within the turbines, fuel NO_x and thermal NO_x are the major contributors, with prompt NO_x contributing slightly only in the initial stages of combustion. All three processes are temperature dependent – combustion temperatures below 2700°F greatly inhibit NO_x formation.

5.3.1 Available Control Technology

The following technologies have been identified as potential control methodologies for control of NO_x emissions: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); and EMx™ (previously known as SCONO_x™).

In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine's exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range (typically between 480°F and 800°F with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both NO_x and CO without a reagent such as ammonia. The NO emissions are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the NO₂ from the catalyst and reduce it to N₂ prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, NO₂ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

Two additional post-combustion control systems were also identified as being potentially applicable:

Linde's LoTOx™ technology uses ozone injection to oxidize NO and NO₂ to N₂O which is highly soluble and easier to remove through the use of another control device such as a wet

scrubber. UDAQ has seen and permitted the application of this technology in combination with a wet gas scrubber for emission control at a petroleum refinery.

Enviroscrub's Pahlmann™ Process is a sorbent-based control system which functions similarly to a dry scrubber. In this system, Pahlmanite (a manganese dioxide sorbent) is injected into the exhaust stream for NO_x removal and then collected in a particulate control device like a baghouse. The sorbent is then regenerated in an aqueous process, filtered and dried, and is then ready for reinjection. The wastewater is sent offsite for disposal.

5.3.2 Evaluation of Technical Feasibility of Available Controls

All of the identified control options are potentially technically feasible; however some additional explanation is warranted:

In the case of LEC, more than one variant of combustor design exists:

- **Dry-low-NO_x:** The modern, dry low-NO_x (DLN) combustor is typically a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperatures, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to approximately 87 percent over a conventional combustor.
- **Catalytic combustors:** These combustors use a flameless catalytic combustion module to initiate the combustion process, followed by a more traditional combustion process downstream of the catalyst. This two-stage process lowers the overall combustion temperature.
- **Xonon Cool Combustion®:** Catalytica Energy Systems' Xonon Cool Combustion® System is a specific type of catalytic combustion process, and often mentioned independently in control technology reviews. In practical application, however, it functions similarly to other catalytic combustors.

Along with these types of burner designs, another pre-combustion process – water or steam injection – can also be used to lower the combustion temperature. Depending on the amount of water or steam used, this process can also increase both the maximum and actual power output of the turbine – by allowing more fuel to be burned without overheating, and by increasing the density of the exhaust flow through the turbine. While the use of water/steam injection is of limited effectiveness in combined cycle systems (those using a HRSG in combination with the CT); employing this process on simple cycle turbines can yield substantial NO_x reductions – as much as 80 to 90% in some cases. This process is technically feasible and is currently in use on all the Gadsby turbines.

Neither the LoTOx™ nor Pahlmann™ processes are determined to be technically feasible. While the LoTOx™ system is technically feasible from a mere engineering standpoint, it suffers from two flaws. It has not yet reached the commercial stage for large scale, combustion turbines; and it requires the use of a second control system, such as a wet gas scrubber, for final removal of the N₂O. In the application of LoTOx™ UDAQ has previously permitted, the system was included as an additional module to a wet gas scrubber designed for removal of SO₂ and other acid gases. Achieving additional NO_x removal at relatively low cost (on a \$/ton basis) was the ideal fit for this technology. However, requiring the addition of another control system for final pollutant

removal, especially where the secondary system does not add to emission reduction of other pollutants, demonstrates that LoTOx™ is not yet technically feasible. Similarly, the Pahlmann™ Process also requires the addition of: a baghouse for particulate removal (for capture of the sorbent), an aqueous sorbent regeneration process, and a wastewater treatment/disposal process. While the technology does show promise for control of multiple pollutants, it was not intended for control of only the NO_x emissions from gas-fired turbines and is not commercially available for such units. Both processes are eliminated from further consideration.

SNCR requires relatively high exhaust gas temperatures for effective NO_x removal. Unlike SCR systems, which rely on the use of a catalyst bed to lower the activation temperature of the reagent, SNCR systems simply inject the reagent directly into the hot exhaust stream (or into the late stages of combustion), and rely on turbulence and residence time for the control of NO_x to take place. However, the temperature of the exhaust stream needs to be between 1,600°F and 2,100°F for the highest degree of control. This is well above the exhaust temperature of the LM6000 turbines in use at the Gadsby plant. The LM6000 turbine is an aero-derivative turbine design, with a much lower exhaust temperature than the more common F-class turbine – such as the GE Frame 7-FA in use at the PacifiCorp Lake Side facility. As the control process cannot function properly without supplemental heat input (which negates the purpose of the system), SNCR is eliminated from further consideration.

Catalytica Energy Systems' Xonon Cool Combustion® System, and other catalytic combustion systems, would require a complete redesign of the burner system and combustion chamber – or replacement of the existing CTs with new CTs built with the alternate combustion process in place as a design element. Such a redesign and/or replacement would have exorbitant costs and would require several years to construct/install. During this time, the existing plant would not be available for power production – severely impacting the local and regional power grids and requiring far more power to be generated from other area plants. This process merely shifts the source of the pollution, rather than reducing overall pollution. UDAQ has determined that for purposes of the PM_{2.5} Serious SIP, catalytic combustion systems, such as Xonon®, are not technically feasible.

The EMx™ system has been demonstrated commercially in five applications – none of which have been simple cycle combustion turbines. The unique catalyst in EMx systems has the opposite problem of SNCR systems, as it operates most effectively in a temperature range of 300-700°F. The average exhaust temperature of the LM6000s installed at Gadsby is 825°F – well above the operating range required for an EMx™ system. EMx™ will not be evaluated further.

The other control options (SCR, good combustion practices, water/steam injection and burner design) are all technically feasible.

5.3.3 Evaluation and Ranking of Technically Feasible BACT Controls

Each of the three LM6000 turbines are built around a standard combustor and further controlled by water injection in the inlet combustion air and downstream through use of a SCR system (complete with ammonia injection). This represents the base case for the Gadsby plant.

The use of water/steam injection as a pre-combustion control was determined to be technically feasible; however it cannot be used in conjunction with the DLN combustor, due to how that combustor operates. Aside from the obvious problem with the name (“dry” low-NO_x), the DLN-type combustor is a lean pre-mix burner design, which uses a combination of staged combustion and differing fuel-air mixing for each combustion stage to lower the combustion temperature, yet

still allow for complete combustion. The injection of water or steam into the inlet combustion air alters the availability of oxygen in the inlet stream. While a large amount of combustion air is provided, only limited fuel is injected in the initial primary stage of the combustor. Including water vapor consumes much of the “additional” combustion air volume, reducing the leanness of the combustion mix and reducing the benefit of the staged combustion design. Plus the addition of the water vapor serves to dampen the combustibility of the fuel-air mixture even more than normal (from the initial non-stoichiometric fuel-air ratio), owing to water’s high specific heat. This can prevent the turbine from maintaining consistent combustion; leading to flameouts, poor performance, or inadequate combustion and increased emissions. For this reason, turbines using water/steam injection for NO_x control are fitted with standard burners, and the use of DLN in this case will not be evaluated further.

On the other hand, the use of water/steam injection has no impact on the effectiveness of the other remaining technically feasible control system – SCR. The resulting steam leaving the combustion chamber serves merely to increase the mass of the exhaust gases. It does not poison, foul, “clog up” or otherwise affect the catalyst bed of the SCR, and has no impact on the injected reagent – which is most commonly liquid urea or aqueous ammonia. Water/steam injection and SCR are commonly found in use together, and represents the base case for the three turbines at Gadsby.

Since both remaining controls can be used in conjunction, there is no need to rank the two controls.

5.3.4 Further Evaluation of Most Effective Controls

Both control options are in place and operational at Gadsby; thus, there is no need to evaluate these options further.

5.3.5 Selection of BACT Controls

Retention of the existing SCR and water/steam injection systems for each of the three CTs is recommended as BACT to control NO_x emissions. Emission limits were established in the most recently issued NSR permit for the facility, and these emission limits were then updated into daily limits for the moderate PM_{2.5} SIP as follows:

SIP Section IX.H.12.o.

- v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:
 - A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
 - B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

These same emission limits should also be retained as BACT.

5.4 VOC

VOC emissions are the result of unburned hydrocarbons formed during incomplete combustion. To some degree the formation of VOCs is dependent on combustion system design, choice of fuel, combustion temperature (itself dependent on equipment design and operating practices), and operating practices (which can control the air-to-fuel ratio, timing, temperature, and other

factors).

5.4.1 Available Control Technology

Control techniques are divided into two groups: Post-combustion controls, and everything else - which includes pre-combustion controls, as well as equipment design and good operating practices.

Only one type of post combustion control has been identified by UDAQ - the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust stream prior to the final stack, so that emissions of both VOC and CO can be further oxidized to CO₂ and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics. All three CTs at the Gadsby facility have oxidation catalysts installed as these were required as CO/VOC BACT as part of the requirements of the PSD construction permits (UDAQ issued AOs) to initially construct and operate the turbines. The use of oxidation catalysts is thus considered the base case for comparison purposes.

One specialized example of oxidation catalyst, EMx™, has been used to oxidize and remove both NO_x and VOC. The system uses a platinum-based catalyst coated with potassium carbonate (K₂CO₃), and unlike SCR systems, does not require the use of a reagent (such as ammonia) for NO_x control (see Section 5.3 NO_x Control above).

The other available control techniques include the use of:

1. Properly designed combustion chambers/combustors
2. Good combustion practices
3. The Xonon catalytic combustion system

Currently, most properly designed combustion turbines utilize “lean combustion” – where a large amount of excess combustion air is provided. The most effective low-NO_x combustor/burner design is known as the dry low-NO_x (DLN) combustor. Combustion turbines using water/steam injection for NO_x control will always be equipped with standard burners (see Section 5.3.3 above).

Good combustion practices include only using pipeline quality natural gas as fuel, maintaining high combustion efficiencies, maintaining proper air-to-fuel ratios, and conducting proper maintenance.

Calytica Energy Systems’ Xonon Cool Combustion® (Xonon) system is supposed to improve the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies (such as water injection and DLN) cannot provide. The Xonon system uses catalysts within the combustion chamber to oxidize the majority of the air-fuel mixture rather than burning the mixture with a flame. The burners are designed with a high degree of variability in fuel and air mixing, while still operating as lean combustors, so VOC emissions are minimized.

5.4.2 Evaluation of Technical Feasibility of Available Controls

The use of post-combustion oxidation catalysts is technically feasible as they are already installed and operational at the Gadsby CTs.

Good combustion practices and the use of a DLN combustor are similarly technically feasible. This is not the case at Gadsby, as the CTs use water injection for NO_x control. Thus, the Gadsby CTs use standard burners.

The EMx™ process can, in theory, be applied to combustion turbines of any size category; however, commercial experience with the process has not been applied to turbines greater than 50 MW in size. UDAQ conducted a search and was unable to find any commercial applications of EMx™ on large units similar to those at the Gadsby plant. EMx™ equipped turbines experience larger pressure drops than other oxidation catalyst-equipped units, and have not been designed around aero-derivative turbines like the LM6000 class.

Xonon® does not currently represent an available control technology for any large turbine. While a joint venture agreement was in place with General Electric (GE) to eventually develop Xonon® as original and retrofit equipment for the entire GE turbine line, GE does not currently offer a Xonon® combustor option for any large industrial turbine. Currently Catalytica Energy Systems is only marketing Xonon® technology for gas turbines within the 1 to 15 MW size range. Hence, at this time, Xonon® does not represent a currently available control technology for the Gadsby plant.

5.4.3 Evaluation and Ranking of Technically Feasible Controls

The three turbines have all the remaining control options (good combustion practices, properly designed combustors, and oxidation catalysts) as existing controls. There is no need to rank these controls on control effectiveness. However, a comparison can be made between the two burner types to determine if any difference in the control effectiveness on VOCs exists and then an evaluation of the effectiveness on NO_x can be similarly made.

UDAQ conducted a search of recent permitting actions made by other states on other simple-cycle CT projects. It did not appear that any specific comparison of burner type on final VOC limit was made, or that any consideration was included with setting the final limit on VOC emissions. Rather, it appears that a well-designed oxidation catalyst system can control VOC emissions to 2 ppmv on average – regardless of the type of combustor employed.

5.4.4 Further Evaluation of Most Effective Controls

There are minor potential environmental and energy related impacts associated with the use of an oxidation catalyst, such as increased backpressure and the chance for increased H₂SO₄ emissions. These potential impacts are not typically considered problematic enough to prevent installation and use of oxidation catalyst systems on CTs. The existing CTs at Gadsby already have oxidation catalysts installed; however, at a lower efficiency rating than a current well-designed system. The most recent NSR permit has no specific limits on VOCs, but does set limits on CO emissions of 10 ppmvd – UDAQ has found for most natural gas-fired CT oxidation catalyst systems the emission rate for CO and VOC are roughly equivalent.

Therefore, evaluation of potential BACT must also include installation of a more efficient oxidation catalyst, or upgrading the existing catalyst to meet current efficiency ratings. PacifiCorp provided a cost analysis for the second option – presumably the lower overall cost of the two choices. By upgrading the efficiency of the catalyst bed and reducing the emission rate, PacifiCorp estimated a reduction of 1.6 tons of VOC annually, with a control efficiency of \$65,000/ton removed.

5.4.5 Selection of BACT

Retention of the existing control systems (good combustion practices, and the existing oxidation catalysts) for control of VOC emissions is recommended as BACT.

In the most recent NSR permit issued to the plant, DAQE-AN103550015-09, the oxidation catalysts installed on the CT/HRSGs on Block #1 lower the CO emission rate down to 10 ppm per turbine stack, with a combined limit on all three turbines of 26.9 lb/hr. While there is no specific VOC emission limit, it is assumed that VOC emissions on a ppm basis are similar to CO emissions. The limitations on CO were not brought forward into the moderate PM_{2.5} SIP, as emissions of NO_x were determined to be the limiting factor on turbine operation.

5.5 Startup and Shutdown

Operation of a natural gas-fired combustion turbine requires periods of startup and shutdown. These events are a normal part of power plant operation, but as they result in NO_x emission rates that are both highly variable and with values typically greater than during normal (steady-state) operation. The reason for higher NO_x emissions is that the emission control systems are not fully functioning during startup and shutdown periods. Although the standard combustors installed on these turbines do not have the same minimum operating rate issues that DLN combustors can have, the water/steam injection system can cause problems with flame retention if the firing rate is too low. At the same time, the catalyst in the SCR control system will be too cold to be effective. Normally, the catalysts will be heated to a minimum operating temperature before the system is even brought online to avoid thermal shock and premature degradation of the catalysts. Since these periods of startup and shutdown can even be defined as the period when no emission controls are operating, such as is the case at Gadsby, the easiest way to minimize emissions is to limit the total number and total duration of these events.

The Gadsby turbines are operated as peaking units, averaging between 2200 and 4600 operating hours per year. Each turbine will experience several startup/shutdown events in a given rolling 12-month period.

UDAQ did search for alternative control options during startup and shutdown periods, but was unable to find any viable alternatives. Using an alternative, lower efficiency control for NO_x control – such as SNCR – during startup or shutdown is plagued by the same problems as the steady-state case (operating temperature, infrastructure, secondary control system) only these become exaggerated the more that the operating rate drops towards zero. And using an alternative combustor during startup periods is physically impossible, as the combustor is integrated into the unit and obviously cannot be “swapped out” during operation.

Since no catalytic control options can be used until a viable operating temperature has been reached, and simply injecting ammonia or urea would be similarly ineffective, the simplest solution remains limiting the frequency and duration of startup and shutdown events. Frequency of startup and shutdown is a function of power demand, equipment maintenance, and operator work experience to adjust event timing and load balance. Event duration can be adjusted by several factors: including the above work practices, manufacturer’s specifications and recommendations.

Beyond these work practice techniques, there are no other technically feasible control methods to reduce emissions during periods of startup or shutdown. For the Gadsby plant, startup and

shutdown periods and work practice standards were defined in the moderate PM_{2.5} SIP. It is recommended that these definitions be brought forward for the serious PM_{2.5} SIP. These definitions are listed below.

- vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan
 - A. Startup begins when the fuel valves open and natural gas is supplied to the combustion turbines
 - B. Startup ends when either of the following conditions is met:
 - I. The NO_x water injection pump is operational, the dilution air temperature is greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia block valve has opened and ammonia is being injected into the SCR and the unit has reached an output of ten (10) gross MW; or
 - II. The unit has been in startup for two (2) hours.
 - C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW with the intent of removing the unit from service.
 - D. Shutdown ends at the cessation of fuel input to the turbine combustor.
 - E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.
 - F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with an electrical meter

6.0 Additional Sources

There are several minor sources of emissions at the Gadsby plant. Each of the three main utility boilers is connected to a cooling tower, which is a source of particulate emissions. There are two diesel-fired, emergency engines, and nine, fixed-roof, miscellaneous storage tanks. Finally, the source conducts a limited amount of abrasive blasting and painting operations as part of general maintenance. Each of these will be addressed below.

6.1 Cooling Towers

The steam generated by the three main utility boilers is cooled by three separate heat exchange systems – each using a cooling tower. The system circulates cooling water through the heat exchanger, where it removes the heat from the steam lines following power generation at the steam turbine. The now heated water then passes down through the cooling tower as air is drawn up through the tower to evaporate a portion of the water and cool the remainder. Particulate emissions can result from dissolved solids carried in the liquid which condense into small particles as the liquid is evaporated. To prevent these particles from being carried out of the cooling tower into the ambient air as particulate emissions, cooling towers are fitted with drift eliminators – a series of baffles that forcibly redirect the exhaust stream from side to side. The changes in direction affect the momentum of the particles more than the momentum of the air molecules; the exhaust air can make the multiple turns, while the particulates are captured and eventually fall back into the cooling tower where they dissolve or are removed by particulate filters. The most common method of reducing particulate emissions is to install high-efficiency drift eliminators.

There are other, alternative methods of controlling particulate emissions. Dry cooling, which uses air-cooled radiator-like systems to remove heat has been employed in areas with little naturally available water supply, or where the local water requires excessive treatment prior to use. Limiting the total dissolved solids in the cooling water supply by water treatment has also been used, but this method has diminishing returns. For economic and convenience reasons the

most common cooling process is the use of cooling towers.

Currently the drift eliminators at the Gadsby plant cooling towers are rated at 0.002% drift – which qualifies as high-efficiency, but more modern systems with ratings as low as 0.0005% have been achieved. PacifiCorp has submitted a cost analysis for upgrading the drift eliminators and found that the average cost per ton would be approximately \$159,000 – for a possible reduction of 7.5 tons of PM₁₀ (there are no specific calculation methodologies established for estimating the emissions of PM_{2.5} from cooling towers – all values given in AP-42 and other sources are listed as PM₁₀). This is not economically feasible. It is recommended that the existing drift elimination system remain in place. As no specific emission limitations have been established in either the most recent NSR permit or the moderate PM_{2.5} SIP, this system would be considered a work practice, and thus BACM.

6.2 Diesel-fired Emergency Engines

There are two diesel-fired emergency engines installed at the Gadsby facility. Both engines supply power to the control rooms and control & emergency equipment if there is a loss of line power or other emergency. This allows for the safe shutdown of the boilers and/or turbines if such becomes necessary.

UDAQ has completed a separate analysis of specific similar emission units which are common to many sources such as emergency generators. Refer to the BACT analysis for Small Sources for details of that analysis.

PacifiCorp's own analysis was similar to UDAQ's and arrived at the same conclusion – replacement of existing emergency equipment already subject to the emission standards of NSPS Subpart IIII was cost prohibitive. Similarly, retrofitting these engines with new controls, such as diesel particulate filters (DPFs), SCR, or oxidation catalysts, was similarly cost prohibitive. These engines are run rarely – periodically for testing and routine maintenance, and are already subject to the emission standards of NSPS Subpart IIII. They are also required to burn only ULSD. These limitations and requirements are adequate to serve as BACM for these engines.

6.3 Fuel Storage Tanks

There are nine storage tanks at the Gadsby plant used to store diesel fuel, lube oils, water treatment chemicals, and water treatment sludge. None of the storage tanks at the Gadsby facility are used to store liquids with a vapor pressure greater than 0.02 psia and none are larger than 4,200 gallons. Please refer to the BACT analysis for Small Sources – Section 13A for details on UDAQ's analysis on VOC Liquid Storage Tanks. The analysis shows that the only feasible control option is the use of submerged fill pipes. PacifiCorp submitted a similar analysis which arrived at the same conclusion.

6.4 Abrasive Blasting

The Gadsby plant performs a limited amount of abrasive blasting to clean parts prior to painting or performing other maintenance. These operations take place inside a dedicated booth. UDAQ has performed a separate analysis of abrasive cleaning/blasting which can be found in the BACT analysis for Small Sources – Section 1. Please refer to that analysis for specific details. The results of that analysis are that abrasive blasting operations should be conducted in an enclosed booth and controlled with a baghouse or similar particulate control device. Unconfined abrasive blasting operations may only be conducted if the item to be blasted exceeds 8 feet in any

dimension or the surface being blasted is situated at its permanent location. Unconfined abrasive blasting must be conducted using wet abrasive blasting, blasting with reclaim systems, or the abrasives defined in R307-306-6(2). The Gadsby facility is subject to these restrictions by rule, so additional requirements or limitations are not necessary.

6.5 Miscellaneous Painting Operations

There is a limited amount of painting performed at the Gadsby facility for maintenance, preventative care, and other miscellaneous tasks. Total emissions from all painting operations are less than one ton per year (both VOCs and particulates). Paint activities can take place in an enclosed paint booth (for small parts or equipment), or externally on affixed, in-place equipment.

Although some capture and control systems exist for painting operations, all such systems rely on an adequate VOC loading to be viable and cost effective. Maintenance painting operations such as those performed at the Gadsby plant are inadequate for the use of such systems.

The use of low-VOC compliant coatings; good housekeeping practices; and high transfer efficiency application techniques are all viable control options and represent BACM in this case.

7.0 Ammonia Considerations

There is only one source of emissions of ammonia at the Gadsby plant. The SCR units used to control emissions of NO_x from the CTs use ammonia injection to reduce NO_x to N₂ and water. The catalyst serves to lower the reaction temperature required and helps speed the process. Ideally, a stoichiometric amount of ammonia would be added – just enough to fully reduce the amount of NO_x present in the exhaust stream. However, some amount of ammonia will always pass through the process unreacted; and since the process possesses some degree of variability, a small amount of additional ammonia is added to account for minor fluctuations. The ammonia which passes through the process unreacted and exits in the exhaust stream is termed “slip” (sometimes “ammonia slip”). The amount varies from facility to facility, but ranges from almost zero to as high as 30 ppm in poorly controlled systems. Also, as catalyst systems degrade over time, the degree of ammonia slip will gradually increase as increasing amounts of ammonia are added to maintain NO_x reduction performance.

The unreacted ammonia is treated as a PM_{2.5} precursor. The source’s BACT analysis did include an analysis of BACT for ammonia emissions.

7.1 Available Control Technology

There is only one control technique considered available for ammonia emissions. Monitoring of ammonia slip emissions and setting a “not to exceed” emission rate limitation. This allows for setting up a feedback process where the source can adjust ammonia injection rates based on both parameters: NO_x emission reduction levels and ammonia slip levels. Should catalyst activity, over time, degrade to the point where both parameters cannot be met, then the SCR catalyst should be replaced.

7.2 Evaluation of Technical Feasibility of Available Controls

This represents a work practice standard, and is inherently technically feasible.

7.3 Evaluation and Ranking of Technically Feasible Controls

A review of recently issued permits for SCR units at large combustion turbine installations reveals NH₄ emission limits ranging between 2.0 ppm and 5.0 ppm. Permits issued during the same time period as the Gadsby construction permit for Units #4-6 routinely had NH₄ emission limits around 10 ppm.

7.4 Further Evaluation of Most Effective Controls

The source has not provided a cost effectiveness breakdown for upgrading the ammonia injection system at the Gadsby plant so that a new limitation of 5 ppm could be established. This is not an easy task, as it is not as simple as merely upgrading the injection system. An entire SCR upgrade might be required to guarantee that the SCR unit itself was still operating with required removal efficiency at the tighter ammonia injection levels. Increased monitoring would also be required.

However, should this be required, ammonia emissions, currently estimated at 13.15 tons per year, could be reduced to 6.58 tons.

7.5 Selection of BACT

Given the difficulty in redesigning a new SCR system for control of a pollutant not currently listed as a precursor pollutant, and the expected high cost for this process, no change in ammonia slip requirements is recommended at this time. Retention of the existing ammonia slip design parameter of 10 ppm as a limitation is recommended as BACT. This limit is based on the Gadsby plant's existing SCR catalyst system which is designed with an "end of life" ammonia slip of 10 ppmvdc. Existing work-practice standards should suffice to minimize emissions.

8.0 Additional Feasible Measures and Most Stringent Measures

8.1 Extension of SIP Analysis Timeframe

As outlined in 40 CFR 51.1003(b)(2)(iii):

If the state(s) submits to the EPA a request for a Serious area attainment date extension simultaneous with the Serious area attainment plan due under paragraph (b)(1) of this section, such a plan shall meet the most stringent measure (MSM) requirements set forth at § 51.1010(b) in addition to the BACM and BACT and additional feasible measure requirements set forth at § 51.1010(a).

Thus, with the potential for an extension of the SIP regulatory attainment date from December 31, 2019 to December 31, 2024, the SIP must consider the application of both Additional Feasible Measures (AFM) and Most Stringent Measures (MSM).

8.2 Additional Feasible Measures at Gadsby

As defined in Subpart Z, AFM is any control measure that otherwise meets the definition of "best available control measure" (BACM) but can only be implemented in whole or in part beginning 4 years after the date of reclassification of an area as Serious and no later than the statutory attainment date for the area. The Salt Lake City Nonattainment Area was reclassified as Serious on June 9, 2017. Therefore, any viable control measures that could only be implemented in whole or in part beginning 6/9/2021 (4 years after the date of reclassification) are classified as AFM.

After a review of the available control measures described throughout this evaluation report, UDAQ was unable to identify any additional control measures that were eliminated from BACT consideration due to extended construction or implementation periods. Although there are some instances where technologies or control systems were removed from further consideration based on a lack of commercial or technological development, such as EMx™ or NO_x absorber systems, there is no evidence to suggest that these systems will become viable for application merely by waiting 4 years. In addition, existing BACT controls on the emitting units where these alternative controls might have been applied will achieve the same or potentially greater levels of emission reduction; thus rendering the hypothetical discussion moot.

8.3 Most Stringent Measures at Gadsby

As defined in Subpart Z, MSM is defined as:

... any permanent and enforceable control measure that achieves the most stringent emissions reductions in direct PM_{2.5} emissions and/or emissions of PM_{2.5} plan precursors from among those control measures which are either included in the SIP for any other NAAQS, or have been achieved in practice in any state, and that can feasibly be implemented in the relevant PM_{2.5} NAAQS nonattainment area.

This is further refined and clarified in 40 CFR 51.1010(b), to include the following Steps:

- Step 1) The state shall identify the most stringent measures for reducing direct PM_{2.5} and PM_{2.5} plan precursors adopted into any SIP or used in practice to control emissions in any state.
- Step 2) The state shall reconsider and reassess any measures previously rejected by the state during the development of any previous Moderate area or Serious area attainment plan control strategy for the area.
- Step 3) The state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part by 5 years after the applicable attainment date for the area, and may eliminate such whole or partial measure from further consideration.
- Step 4) Except as provided in Step 3), the state shall adopt and implement all control measures identified under Steps 1) and 2) that collectively shall achieve attainment as expeditiously as practicable, but no later than 5 years after the applicable attainment date for the area.

8.3.1 Step 1 – Identification of MSM

For purposes of this evaluation report UDAQ has identified for consideration the most stringent methods of control for each emission unit and pollutant of concern (PM_{2.5} or PM_{2.5} precursor). A summary is provided in the following table (the minor emission sources found in Section 6 are not listed):

Table 8-1: Most Stringent Controls by Emission Unit

Emission Unit	Pollutant	Most Stringent Control Method
Utility Boilers	PM _{2.5}	GCP, proper burner design, natural gas
	SO ₂	use of natural gas
	NO _x	SCR
	VOC	oxidation catalysts
	PM _{2.5}	inlet air filters, proper combustors, natural gas, GCP

Combustion Turbine	SO ₂	use of natural gas
	NO _x	water/steam injection, SCR w/ ammonia injection
	VOC	GCP, oxidation catalysts
	SU/SD	work practice standards
Ammonia	NH ₄	redesigned SCR w/ improved NH ₄ injection

The above listed controls represent the most stringent level of control identified from all other state SIPs or permitting actions, but do not necessarily represent the final choice of MSM. That is determined in Step 4.

8.3.2 Step 2 – Reconsideration of Previous SIP Measures

Utah has previously issued a SIP to address the moderate PM_{2.5} nonattainment areas of Logan, Salt Lake City, and Provo. The SIP was issued in parts: with the section devoted to the Logan nonattainment area being found at SIP Section IX.A.23, Salt Lake City at Section IX.A.21, and Provo/Orem at Section IX.A.22. Finally, the Emission Limits and Operating Practices for Large Stationary Sources, which includes the application of RACT at those sources, can be found in the SIP at Section IX Part H. Limits and practices specific to PM_{2.5} may be found in subsections 11, 12, and 13 of Part H.

Accompanying Section IX Part H was a Technical Support Document (TSD) that included multiple evaluation reports similar to this document for each large stationary source identified and listed in each nonattainment area. UDAQ conducted a review of those measures included in each previous evaluation report which contained emitting units which were at all similar to those installed and operating at the LSPP.

There were several technologies that had been eliminated from further consideration at some point during many of the previous reviews. Some emitting units were considered too small, or emissions too insignificant to merit further consideration at that time. The cost effectiveness considerations may have been set at too low a threshold (a question of cost in RACT versus BACT). And many cases of technology being technically infeasible for application – such as applying catalyst controls to infrequently used emitting units which may never reach an operating temperature where use of the catalyst becomes viable and effective.

In all but one case, these rejected control technologies were already brought forward and re-evaluated using updated information (more recent permits, emission rates and cost information) by the Gadsby plant in its BACT analysis report. The one case which was not reconsidered was the deferment of VOC controls for the wastewater treatment systems at four Salt Lake City area refineries. This issue does not apply at Gadsby. Although some amount of water treatment does take place, this is for pre-treatment of the water used in the boilers, cooling towers and for the steam injection system at the combustion turbines and not wastewater treatment in the traditional sense. No VOC-laden water of any sort needs to be treated. Thus, there are no additional technologies identified in Step 2.

8.3.3 Step 3 – Demonstration of Feasibility

A control technology or control strategy can be eliminated as MSM if the state demonstrates that it is either technically or economically infeasible.

This demonstration of infeasibility must adhere to the criteria outlined under §51.1010(b)(3), in

summary:

- 1) When evaluating technological feasibility, the state may consider factors including but not limited to a source's processes and operating procedures, raw materials, plant layout, and potential environmental or energy impacts
- 2) When evaluating the economic feasibility of a potential control measure, the state may consider capital costs, operating and maintenance costs, and cost effectiveness of the measure.
- 3) The SIP shall include a detailed written justification for the elimination of any potential control measure on the basis of technological or economic infeasibility.

This evaluation report serves as written justification of technological or economic feasibility/infeasibility for each control measure outlined herein. Where applicable, the most effective control option was selected, unless specifically eliminated for technological or economical infeasibility. Expanding on the previous table, the following additional information is provided:

Table 8-2: Feasibility Determination

Emission Unit*	Pollutant	MSM Previously Identified	Is Method Feasible?
Utility Boilers	PM _{2.5}	GCP, proper burner design, natural gas	Yes
	SO ₂	use of natural gas	Yes
	NO _x	SCR	No, high cost
	VOC	oxidation catalysts	No, high cost
Turbines	PM _{2.5}	inlet air filters, natural gas, GCP	Yes
	SO ₂	use of natural gas	Yes
	NO _x	water injection, SCR w/ ammonia	Yes
	VOC	GCP, oxidation catalysts	Yes
	SU/SD	work practice standards	Yes
Ammonia	NH ₄	redesigned SCR, improved NH ₄ system	No, high cost

* AFM/MSM for the minor sources found in Section 6 was not further evaluated as these sources were primarily reviewed under the Small Source BACT Analysis document found outside this review.

Many of the entries in the above table were determined to be feasible on both a technological and economic basis. In each of those cases, the control technique listed represents BACT/BACM as well as MSM, so no changes need to take place if implementation of MSM becomes a requirement. For the remaining entries, a more detailed analysis is required.

Utility boilers NO_x control: The installation of ultra-low-NO_x burners (ULNB) with integral flue gas recirculation (FGR) was determined to be economically infeasible for boilers of this size and emission rate. Upgrading to this level of control is technically feasible, but could only be accomplished at a cost effectiveness of \$66,000/ton for Unit #3. The cost effectiveness values for Units #1 and #2 were over \$200,000/ton each. This is considered outside the normal range of economic feasibility. The total tonnage reduced would be a combined 93 tons for all three utility boilers combined. The existing BACT evaluation should also serve as MSM. Should the installation of MSM be required at a future date due to monitored nonattainment concerns, this issue can be revisited.

Utility Boilers VOC control: The only identified control mechanism beyond good combustion practices is installation of oxidation catalysts. However, at a control cost of over \$1.2M/ton, these are not economically viable.

Ammonia Considerations: At the present time, only a single control technique has been identified for reducing the amount of ammonia emissions released from the Gadsby plant. Given that all of the ammonia is released as slip from the SCR units controlling the CTs, reducing ammonia emissions requires reducing ammonia slip. This requires, at minimum, a redesign of the ammonia injection system on the existing SCR, and most likely a redesign of the SCR itself, in order to improve the efficiency of NO_x removal with less ammonia injection. Less ammonia added, yields less ammonia slip. A redesigned SCR, in whole or in part, has not been investigated as of the publication of this document, but most likely falls outside both the economic and technological consideration windows. The cost per ton is likely to be extremely high, but is unknown at this time, and no additional benefit to NO_x emissions will be gained. Design, timed long term shut-down of the three turbines – likely in stages – ordering of materials, construction, testing, shake down, and demonstration is then likely to fall outside the regulatory attainment window. This renders the change infeasible.

9.0 New PM_{2.5} SIP – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.11. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.11.a below, these general requirements apply to all sources subsequently listed in either IX.H.12 (Salt Lake City) or IX.H.13 (Provo), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

9.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.11.a through IX.H.11.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow in the source specific requirements of IX.H.12 and IX.H.13.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.11.e and IX.H.11.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.11.c.

9.2 Discussion of Attainment Demonstration

As is discussed above in Items 9.0 and 9.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in both the original PM₁₀ and the moderate PM_{2.5} SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

10.0 New PM_{2.5} SIP – Gadsby Specific Requirements

The Gadsby specific conditions in Section IX.H.12 address those limitations and requirements that apply only to the Gadsby Power Plant in particular.

IX.H.12.p.i This condition lists the specific requirements applicable to Steam Generating Unit #1 (Boiler #1).

Subparagraph A: NO_x limit of 179 lbs/hr.

Subparagraph B: requirement to install and operate a NO_x and O₂ CEM to demonstrate compliance with the emission limit in IX.H.12.p.i.A.

IX.H.12.p.ii This condition lists the specific requirements applicable to Steam Generating Unit #2 (Boiler #2).

Subparagraph A: NO_x limit of 204 lbs/hr.

Subparagraph B: requirement to install and operate a NO_x and O₂ CEM to demonstrate compliance with the emission limit in IX.H.12.p.ii.A.

IX.H.12.p.iii This condition lists the specific requirements applicable to Steam Generating Unit #3 (Boiler #3).

Subparagraph A.1: NO_x limit of 142 lbs/hr, applicable between November 1 and February 28/29

Subparagraph A.2: NO_x limit of 203 lbs/hr, applicable between March 1 and October 31

Subparagraph B: requirement to install and operate a NO_x and O₂ CEM to demonstrate compliance with the emission limit in IX.H.12.p.iii.A.

IX.H.12.p.iv This condition lists the fuel requirement applicable to all three boilers.

Subparagraph A: The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during periods of natural gas curtailment and for maintenance firings. Maintenance firings shall not exceed one-percent of the annual plant Btu requirement. In addition, maintenance firings shall be scheduled between April 1 and November 30 of any calendar year. Records of fuel oil use shall be kept and they shall show the date the fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil consumed during each curtailment, and the reason for each firing.

IX.H.12.p.v This condition lists the requirements applicable to all three combustion turbines.

Subparagraph A: Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. It also defines what a “day” is for purposes of this section.

Subparagraph B: requirement to install and operate a NO_x and O₂ CEM to demonstrate compliance with the emission limit in IX.H.12.p.v.A.

IX.H.12.p.vi This condition lists the startup/shutdown emission minimization plan requirements applicable to all three combustion turbines. The requirement also includes a definition of startup, shutdown, and a limit on total hours of operation (2) in startup or shutdown mode, per turbine, per day.

10.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.12.p.i.A is specifically outlined in IX.H.12.p.i.B; IX.H.12.p.ii.A is addressed in IX.H.12.p.ii.B; etc. All NO_x monitoring is covered by CEM. CEM monitoring requirements are found in IX.H.11.f. Recordkeeping is subject to the requirements of IX.H.11.c.

10.2 Discussion of Attainment Demonstration

Gadsby is primarily a source of NO_x emissions. While some direct PM_{2.5} and SO₂ emissions add to the overall contribution from Gadsby, it remains a listed source because of NO_x. Total emissions of NO_x have dropped from 2,983 tons per year in the original PM₁₀ SIP to an estimated 716.1 tons in this latest PM_{2.5} SIP. While primary particulate emissions have increased slightly, this is due primarily to the contribution of condensable particulates, which were not included in the original SIP calculations. Some particulate emissions (primarily PM₁₀ and not PM_{2.5}) are provided by the new cooling towers. Emissions of SO₂ have remained roughly equal.

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**BEST AVAILABLE CONTROL
MEASURE ANALYSES
PACIFICORP'S GADSBY
POWER PLANT**

Prepared for:

PacifiCorp
1407 North Temple, Suite 210
Salt Lake City, Utah 84116

By

Meteorological Solutions Inc. a Trinity Consultants Company
Project No. 04171736

April 2017



EXECUTIVE SUMMARY

In 2006, the United States Environmental Protection Agency (EPA) strengthened the 24-hour PM_{2.5} standard from 65 micrograms per cubic meter (µg/m³) to 35 µg/m³. Three areas of the state (Salt Lake City including Davis County, Logan, and Provo) were designated as nonattainment for the 24-hour PM_{2.5} standard. As of the December 31, 2015 attainment date, all three of Utah's PM_{2.5} nonattainment areas were found to be exceeding the 24-hour PM_{2.5} standard. Thus, EPA reclassified each of the three areas to serious nonattainment.

Once reclassified to serious, the attainment date for the areas is December 14, 2019. A serious nonattainment area PM_{2.5} SIP is being prepared by the Utah Division of Air Quality (UDAQ) following the requirements detailed in 40 Code of Federal Regulations (CFR) 51 Subpart Z. This rule requires the UDAQ to identify, adopt and implement Best Available Control Measures (BACM) on major sources of PM_{2.5} and PM_{2.5} precursors including oxides of nitrogen (NO_x), sulfur dioxide (SO₂), volatile organic compounds (VOC), and ammonia (NH₃).

PacifiCorp's Gadsby Power Plant has potential to emit emissions of PM_{2.5} and/or PM_{2.5} precursors above the 70 tons or more per year and is thus classified as a major source which is subject to the implementation rule. As a major source subject to the rule, the UDAQ has requested assistance from PacifiCorp in determining acceptable pollution controls that meet Best Available Control Technology (BACT)/BACM controls.

BACT/BACM was determined for the Gadsby Power Plant. Table E-1 summarizes the BACT/BACM and emission limits for the Gadsby emission sources.

Table E-1 BACM Summary for Gadsby Power Plant

Pollutant	BACM	Emission Limit
Combustion Turbines (Units #4, #5, and #6, collectively EU#24)		
NO _x	Water injection, selective catalytic reduction, good combustion practices, and use of pipeline-quality natural gas.	5 ppmvd @ 15% O ₂ 30-day rolling average per turbine (steady state) 116 ppmvd @ 15% O ₂ on a 4-hour rolling average 22.2 lb/hr @ 15% O ₂ based on 30-day rolling average (total emissions all turbines)
SO ₂	Use of natural gas and fuel sulfur limit.	≤20 gr/100 scf sulfur content or 0.8% by weight.
PM _{2.5}	Use of Natural gas, air inlet filters, and good combustion practices.	None are being proposed.
VOC	Use of natural gas, oxidation catalyst, and good combustion practices.	None are being proposed.
NH ₃	BACM for NO _x .	Proposing an ammonia slip limit of 10 ppmvdc.

Table E-2 (Continued) BACM Summary for Gadsby Power Plant

Pollutant	BACM	Emission Limit
Electric Generating Utility Boilers (EU#1, EU#2, and EU#3, collectively EU#4)		
NO _x	Low-NO _x burners (LNB) with flue gas recirculation (FGR). Units #1 and #2 have LNB, preliminary economic assessment shows NO _x could be reduced at an annualized cost of \$14,080/ton. Further engineering will be required to determine if installing FGR is technically feasible. Unit #3 is equipped with FGR, installing LNB is not cost effective.	EU#1 - 179 lbs/hr @ 3% O ₂ EU#1 - 336 ppmvd @ 3% O ₂ EU#2 - 204 lbs/hr @ 3% O ₂ EU#2 - 336 ppmvd @ 3% O ₂ EU#3 - 203 lbs/hr @ 3% O ₂ for March 1 through October 31 EU#3 - 142 lbs/hr @ 3% O ₂ for November 1 through February 28[29] EU#3 - 168 ppmvd @ 3% O ₂ Fuel oil may be combusted during natural gas curtailments or maintenance firings. Maintenance firings are limited to April 1 through November 30 not to exceed one percent of total plant BTU requirement
SO ₂	EGUs were found to be BACM based on use of natural gas, fuel sulfur limit, and fuel oil usage limits.	Sulfur content less than 20 grains gr/100 scf (0.8% by weight) for natural gas combustion. Fuel oil is limited to a sulfur content of 0.45% by weight Fuel oil may be combusted during natural gas curtailments or maintenance firings. Maintenance firings are limited to April 1 through November 30 not to exceed one percent of total plant BTU requirement.
PM _{2.5}	Use of natural gas, good combustion practices, and fuel oil usage limits.	None are being proposed.
VOC	Efficient boiler design, using natural gas, good combustion practices, and fuel oil usage limits.	None are being proposed.
Emergency Diesel Engines (EU#10 and EU#25)		
NO _x	Good combustion practices and hours of operation limit.	None are being proposed.
SO ₂	Ultra-low sulfur diesel, good combustion practices, and hours of operation limit.	None are being proposed.
PM _{2.5}	Ultra-low sulfur diesel, good combustion practices, and hours of operation limit.	None are being proposed.
VOC	Good combustion practices, and hours of operation limit.	None are being proposed.
Cooling Towers (EU#7, EU#8, and EU#9)		
PM _{2.5}	Drift eliminators.	None are being proposed.
Abrasive Blasting (EU#5)		
PM _{2.5}	Enclosed blasting with filters and dust collectors.	None are being proposed.
Storage Tanks (EU#11, EU#12, EU#16, EU#20, EU#21)		
VOC	Fixed roof tanks.	None are being proposed.

Table E-3 (Continued) BACM Summary for Gadsby Power Plant

Pollutant	BACM	Emission Limit
Miscellaneous Parts Painting/Paint Storage (EU#17 and EU#19)		
VOC	VOC content of paints, high efficiency application equipment, good housekeeping.	None are being proposed.

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1.0 INTRODUCTION

In 2006, the United States Environmental Protection Agency (EPA) strengthened the 24-hour PM_{2.5} standard from 65 micrograms per cubic meters (µg/m³) to 35 µg/m³. As such, all or portions of seven counties in Utah failed to meet the new 24-hour PM_{2.5} standard. Ultimately, only three areas of the state (Salt Lake City including Davis County, Logan, and Provo) were designated as nonattainment for the 24-hour PM_{2.5} standard. Once an area is designated as nonattainment, the Clean Air Act requires that fine particle pollution be controlled by a state through a state implementation plan (SIP) detailing how and when the 24-hour PM_{2.5} standard would be met are required to be prepared and submitted to EPA for approval.

The moderate PM_{2.5} nonattainment areas were required to meet the new standard by 2014. However, as the SIP for Salt Lake City was nearing completion, the D.C. Circuit Court of Appeals found that EPA had incorrectly interpreted the Clean Air Act when determining how to implement the National Ambient Air Quality Standards (NAAQS) for PM_{2.5}. The January 4, 2013 court ruling held that the EPA should have implemented the PM_{2.5} NAAQS based on both Clean Air Act (CAA) Subpart 1 and Subpart 4 of Part D, Title 1. Previously, EPA had (incorrectly) required states to develop their SIPs based on Subpart 1 only. If a moderate PM_{2.5} nonattainment area is not able to attain the 24-hr PM_{2.5} standard by the December 31, 2015 attainment date, Subpart 4 allows EPA to re-classify that area as a serious PM_{2.5} nonattainment area.

As of the December 31, 2015 attainment date, all three of Utah's PM_{2.5} nonattainment areas were found to be exceeding the 24-hour PM_{2.5} standard, and as such, EPA reclassified each of the three areas to serious.

Once re-classified to serious, the attainment date for the area is December 14, 2019. A new serious area PM_{2.5} SIP is being prepared by the Utah Division of Air Quality (UDAQ) and the requirements of such are detailed in 40 Code of Federal Regulations (CFR) 51 Subpart Z. This rule requires the UDAQ to identify, adopt and implement Best Available Control Measures (BACM) on major sources of PM_{2.5} and PM_{2.5} precursors (sulfur dioxide, oxides of nitrogen, volatile organic compounds, and ammonia).

PacifiCorp's Gadsby Power Plant has potential to emit emissions of PM_{2.5} and/or PM_{2.5} precursors above the 70 tons or more per year and is thus classified as a major source which is subject to the implementation rule. As a major source subject to the rule, the UDAQ has requested assistance from PacifiCorp in determining acceptable pollution controls that meet BACM/Best Available Control Technology (BACT) controls.

This document provides a written evaluation of each available control strategy, taking into account technological and economic feasibility, for PacifiCorp's PM_{2.5} and precursor emission sources, provides documentation to justify the elimination of any available control option, establishes BACM/BACT including emission limits, and emission monitoring requirements for each emission unit.

2.0 FACILITY OVERVIEW

The PacifiCorp Gadsby Power Plant is a natural gas-fired electric generating plant consisting of three (3) steam boilers (Units #1, #2, and #3) and three (3) simple-cycle combustion turbines (Units #4, #5, and #6). The power plant is located at 1407 West North Temple in Salt Lake City, Utah which is in Salt Lake County. Salt Lake County is a nonattainment area for particulate matter less than ten microns (PM₁₀), particulate matter less than 2.5 microns (PM_{2.5}), sulfur dioxide (SO₂) and a maintenance area for ozone (O₃) and carbon monoxide (CO). The plant is also a Phase II Acid Rain source and major source for nitrogen oxide (NO_x) and CO.

Constructed in 1951, Unit #1 is a 65 MW electric generator powered by a 726 MMbtu/hr capacity utility boiler equipped with Low NO_x burners (LNB). Unit #2 is an 80 MW unit constructed in 1952 and is powered by an 825 MMbtu/hr boiler equipped with LNB. Unit #3 is a 105 MW unit constructed in 1955 and is powered by a 1,155 MMbtu/hr boiler and is equipped with flue gas recovery system for NO_x emissions control. Fuel oil may be used in Units #1, #2, and #3 as a back-up fuel during natural gas curtailments and maintenance firings not to exceed one percent of the plant's annual heat input requirement.

Units #4, #5, and #6 are 43.5 MW GE LM6000 PC Sprint natural gas-fueled simple cycle combustion turbine engines that were added to the plant in 2002. Each turbine has a maximum firing rate of 367.6 MMbtu/hr and are equipped with water injection, NO_x Selective Catalytic Reduction (SCR) catalyst, and CO oxidation catalyst. The turbines are subject to New Source Performance Standards (NSPS) Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines).

The plant also has two emergency generators; EU#10 is a 175 kW emergency generator powered by a 280 HP engine and EU#25 is a 1,007 kW Black Start Generator (powered by a 1,350 HP engine) and was added to the plant in 2006. Both generators are subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (40 CFR 63 Subpart ZZZZ) and EU#25 is subject to NSPS Subpart IIII (Stationary Compression Ignition Internal Combustion Engines).

Three cooling towers for the electric generating utility boilers, and several small storage tanks are also located at the Gadsby Power Plant. Table 2-1 presents the Title V Operating Permit (OP) identification, the source identification, a description, status, rating or capacity and the existing or proposed control technologies for each source.

Table 2-1 Emission Unit Information

O.P. ID	Source ID	Source Description	Capacity	Control Technology
II.A.2	EU#1	Steam Generating Unit #1	726 MMBtu/hr	LNB
II.A.3	EU#2	Steam Generating Unit #2	825 MMBtu/hr	LNB
II.A.4	EU#3	Steam Generating Unit #3	1,155 MMBtu/hr	FGR
II.A.5	EU#4	Combined Group of Steam Generating Units #1, #2, & #3	--	--
II.A.6	EU#5	Abrasive Blasting Operation	--	Fabric Filters
II.A.7	EU#7	Emission Unit #1 Cooling Tower	--	Drift Eliminators
II.A.8	EU#8	Emission Unit #2 Cooling Tower	--	Drift Eliminators
II.A.9	EU#9	Emission Unit #3 Cooling Tower	--	Drift Eliminators
II.A.10	EU#10	Emergency Generator	280 HP	--
II.A.11	EU#11	Distillate Fuel Oil Tank	500 gal.	--
II.A.12	EU#12	Lube Oil Storage Tanks	2 x 4,200 gal.	--
II.A.13	EU#13	Oil Storage Area	--	--
II.A.14	EU#15	Miscellaneous Electrical Equipment	--	--
II.A.15	EU#16	Water Treatment Chemical Tanks	--	--
II.A.16	EU#17	Paint Storage Areas	--	--
II.A.17	EU#19	Miscellaneous Parts Painting for Maintenance	--	--
II.A.18	EU#20	Lube Oil Conditioners	975 gal.	--
II.A.19	EU#21	Lube Oil Reservoirs	2 x 2,800 gal. 1 x 3,150 gal.	--
II.A.20	EU#22	Hazardous Waste Storage Area	--	--
II.A.21	EU#23	Water Treatment Sludge Disposal Activities	--	--
II.A.22	EU#24	Natural Gas Simple Cycle Turbine Units	3 x 43.5 MW	Water Injection, SCR, CO catalysts
II.A.23	EU#25	Black Start Generator	1,350 HP	--

3.0 BEST AVAILABLE CONTROL MEASURE SELECTION PROCESS

According to 40 CFR Part 51, Subpart Z, BACM is “any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate PM_{2.5} nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct PM_{2.5} emissions and/or emissions of PM_{2.5} plan precursors from sources in the area than can be achieved through the implementation of RACM on the same source(s). BACM includes BACT”.

In the preparation of this BACM analyses, several sources of information were examined including EPA’s RBLC RACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature.

In the conduct of the BACM analysis, the EPA’s established five-step procedure for determining the appropriate BACT/BACM limit for NO_x, SO₂, PM_{2.5}, and VOC that starts with the most stringent emission limits and lists all control technologies was utilized. This is referred to as “Top-Down” BACT and include the following five steps as outlined in the Draft New Source Review Manual, dated 1990.

3.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. For Step 1, all available control options for each emission unit at the Gadsby Power Plant are identified.

3.2 Step 2 - Eliminate Technically Infeasible Options

The second step in performing the top-down BACT analysis is to eliminate technically infeasible options. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emissions unit under review due to technical difficulties. Two key concepts in determining whether an undemonstrated technology is feasible are availability and applicability. A Technology is considered available if it can be obtained through commercial channels. An available technology is applicable if it can be reasonably installed and operated on the source type under consideration. Technically infeasible control options are then eliminated from further consideration in the BACM/BACT analysis.

3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The third step of the BACM analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. The emission limit or removal efficiency used in the ranking process is the level the technology has demonstrated it can consistently achieve under reasonably foreseeable worst-cast conditions with an adequate margin of safety.

3.4 Step 4 - Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology in order to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Information including control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts are to be considered.

If the top-ranked technology is chosen and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACM/BACT analysis is complete and no further information regarding economic, environmental, and energy impacts is required.

However, if the top-ranked option is not chosen, an assessment of economic, environmental, and energy impacts (taking into consideration source-specific circumstances that distinguish it from other sources where the technology is in use or has been required) is performed on the next most cost-effective technology until the technology under consideration is not eliminated.

3.4.1 Energy Impact

The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

3.4.2 Environmental Impacts

The second evaluation is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology.

3.4.3 Costs of Control

This third evaluation addresses the economic impact of the control technologies. The cost to purchase and to operate the control technology is analyzed. The capital and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. It also compares the potential technologies on an economic basis.

3.5 Step 5 - Selection of BACM/BACT

The fifth, and final, step is selection of the BACM/BACT emission limit corresponding to the most stringent and technically feasible technology that was not eliminated based upon adverse economic, environmental, and energy impacts. BACM/BACT is the technologically and economically feasible control option that can be implemented that achieves permanent and enforceable emissions reductions. It typically is the highest ranked control technology. In addition, the chosen BACM/BACT limit must not be less stringent than any applicable federal NSPS, NESHAP or state-specific standards.

4.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS - NITROGEN OXIDES

BACM's were evaluated for NO_x emissions from certain emission units in operation or proposed at the Gadsby Power Plant. These units include: simple cycle turbines, electric generating utility boilers, and engines.

Nitrogen oxides are formed during the combustion of fuels by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air. There are three different formation mechanisms: thermal, fuel, and prompt NO_x. Thermal NO_x is primarily temperature dependent (above 2000°F); fuel NO_x is primarily dependent on the presence of fuel-bound nitrogen and the local oxygen concentration. Prompt NO_x is formed in relatively small amounts from the reaction of molecular nitrogen in the combustion air with hydrocarbon radicals in the flame front.

4.1 Simple Cycle Gas Combustion Turbines

The Gadsby Power Plant has three 43.5 MW GE LM6000 PC Sprint natural gas-fueled simple cycle combustion turbine engines (Units #4, #5, and #6) located at the west end of the plant. Each unit has a maximum firing rate of 367.6 MMBtu/hr and are equipped with water injection and SCR.

4.1.1 Step 1 - Identify All Existing and Potential Emission Control Techniques

Potentially available technologies for controlling NO_x were identified based on a comprehensive review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), state databases, and emission control literature. NO_x control methods are categorized into two methods: combustion controls and post-combustion control. The combustion controls for NO_x formation minimize the amount of NO_x formed from the combustion turbine; the post-combustion controls reduce the NO_x emissions in the fuel gas stream after NO_x has been formed in the combustion process. Both of these methods can be used alone or in combination to achieve various degrees of NO_x control. Below is a list of control options evaluated for BACM:

1. Dry Low-NO_x (DLN) Combustors
2. Selective catalytic reduction (SCR)
3. Selective non-catalytic reduction (SNCR)
4. Water/Steam Injection
5. EM_xTM
6. NO_xOUTTM SNCR Process
7. XONONTM, LoTO_xTM, THERMALLONO_xTM, and PahlmannTM

Each control technology is described in detail below.

4.1.1.1 Dry Low-NO_x Combustors

Dry Low-NO_x combustors are commonly used in simple-cycle turbines. Excess air in lean combustion cools the flame and reduces the rate of thermal NO_x formation. Premixing air and gaseous fuel prior to combustion can further reduce NO_x emissions by minimizing "hot pockets" and fuel rich zones within the combustion chamber. DLN combustors have been shown to reduce NO_x emissions from turbines by 75 to 90 percent with vendor-guarantees of 9 to 25 ppmvd.

4.1.1.2 Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) is an add-on post-combustion NO_x control technology that is widely used. SCR systems react the NO_x in the turbine exhaust with ammonia or urea and oxygen in the presence of a catalyst to form nitrogen and water. SCR technology requires optimal gas temperatures in the range of 480°F to 800°F. NO_x conversion is sensitive to exhaust temperature and performance can be limited by contaminants in the exhaust gas that may poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream. The SCR catalyst requires periodic replacement. SCR is a widely used post-combustion NO_x control technique on utility-scale gas turbines in conjunction with combustion controls and has been demonstrated to achieve NO_x emission limits of 5 ppmvd.

4.1.1.3 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) reduces NO_x emissions by injecting of ammonia or urea with proprietary chemicals into the exhaust stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°F and is most commonly used in boilers because gas turbines do not have exhaust temperatures in that range.

4.1.1.4 Water/Steam Injection

The injection of water or steam into filter plane and compressor inlet of the combustion turbine is a combustion technique that reduces the air temperature as it enters the combustor. The lower air temperature entering the combustor reduces the peak temperature of the combustion reaction and thus lowering the quantity of thermal NO_x formed. The amount of NO_x reduction is a function of the combustor design and the water-to-fuel ratio employed. An increase in the steam/water-fuel ratio causes a decrease in NO_x emissions.

However, the lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion potentially causing CO and precursor organic compound (POC) emissions to increase as steam/water-fuel ratios increase. The injected water or steam exits the turbine as part of the exhaust. Water or steam injection systems have been demonstrated to control NO_x emissions by 80 to 90 percent with vendor-guarantees in the range of 25 to 45 ppmvd at 15 percent oxygen.

4.1.1.5 EM_x

Formerly SCONO_x[™], EM_x[™] is a catalytic oxidation and absorption control technology distributed by EmeraChem. This system uses a platinum-based oxidation catalyst coated with potassium carbonate (K₂CO₃) to oxidize and remove NO_x, and CO without a reagent such as ammonia.

The K₂CO₃ coated catalyst oxidizes CO to CO₂, NO to NO₂, and hydrocarbons to CO₂ and water. CO₂ generated in the catalyst bed is exhausted to the atmosphere with the flue gas while NO₂ absorbs onto the catalyst to form potassium nitrite (KNO₂) and potassium nitrate (KNO₃).

The EM_x[™] system utilizes hydrogen as the basis for a propriety catalyst regeneration process. The regeneration step converts KNO₂ and KNO₃ into K₂CO₃, water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of five-module catalyst sections. During operation, four of the five modules are online and treating the flue gas while one module is not in use. NO_x reduction in the system occurs in an operating temperature range of 300°F to 700°F.

4.1.1.6 NO_xOUT™ SNCR Process

Fuel Tech's NO_xOUT™ process is a urea-based SNCR process for reduction of NO_x from stationary sources. The NO_xOUT™ process requires precisely engineered injection of stabilized urea liquor into combustion flue gas. NO_x reduction occurs in the temperature range of 1,650°F to 2,100°F.

4.1.1.7 XONON™, LoTOx™, THERMALLONox™, and Pahlmann™

A number of NO_x emission control technologies are being marketed for combustion turbines including XONON™, LoTOx™, THERMALLONox™, and Pahlmann™.

XONON™, developed by Catalytica Combustion Systems, is another form of in-combustor control. XONON prevents the formation of NO_x emissions by keeping the temperature of flame below (2700°F) and combustion below the level that permits nitrogen and oxygen to combine and form NO_x. XONON™ uses a proprietary flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. XONON™ has shown to be a promising pollution prevention device for both simple-cycle and combined-cycle gas turbine power plants. XONON™ has been used successfully on gas turbines <15 MW but have not been demonstrated on large-scale utility gas turbines such as the GE LM6000 PC turbines located at the Gadsby Power Plant.

LoTOx™, THERMALLONox™, and Pahlmann™ have not reached the commercial development stage for large combustion turbines fired with natural gas and, thus, are not technically feasible control technologies suitable for the Gadsby Power Plant combustion turbines.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

State-by-state reviews as well as the EPA's RACT/BACT/LAER Clearinghouse databases were searched to identify facilities with simple-cycle combustion turbines utilizing NO_x controls listed in Table 4-1. The databases do not contain data suggesting that XONON has been used successfully on gas turbines larger than 15 MW. Thus, since this technology has not been demonstrated on large-scale utility gas turbines, such as the GE LM6000 PC located at the Gadsby Power Plant, it is not considered technically feasible and has been eliminated from further BACM consideration.

SNCR is also eliminated from further BACM evaluation since the technology requires temperatures of the exhaust stream in the range of 1,600°F to 2,100°F which is well above the 825°F exhaust temperatures output by the GE LM6000 PC turbines.

Similar to SNCR, the NO_xOUT™ SNCR process can also be eliminated from further evaluation since the technology requires exhaust gas temperatures in the range of 1,650°F to 2,100°F to be effective. This is also much higher than the 825°F exhaust temperatures from the GE LM6000 PC turbines.

EM_x™ has been commercially demonstrated in five applications with no demonstrations of the EM_x™ technology's effectiveness on simple-cycle turbines. The EM_x™ technology is designed to effectively reduce NO_x in the exhaust stream in an operating temperature range of 300°F to 700°F and requires steam as a carrier gas for hydrogen to regenerate the catalyst. Steam is not generated from turbines operated in a simple-cycle configuration and would require the installation of a steam boiler to be effective. In addition, combustion gas temperatures from the GE LM6000 PC turbines are above the upper limit of the EM_x™ system to effectively remove NO_x. Therefore, EM_x™ is technically infeasible and is removed from further BACM consideration.

Water/Steam injection is a technically feasible and widely used technology in simple-cycle configurations. The technology has not proven capable of achieving emissions as low as 5 ppmvd at 15 percent oxygen as a standalone technology and would require a post-combustion add-on, such as SCR to further reduce NO_x emissions.

After review of EPA and State databases, lean burn practices using DLN combustors is a technically feasible and widely used technology for simple-cycle turbines. However, the simple cycle turbines at Gadsby utilize water injection to reduce NO_x emissions and water injection is not compatible with DLN burners. Thus, DLN combustors has been determined to be technically not feasible.

SCR is a post-combustion NO_x control technology that is a proven and technically feasible technology that is been widely used in simple-cycle turbine configurations. When combined with water/steam injection or DLN burners, it is capable of achieving the 5 ppmvd at 15 percent oxygen.

4.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The most effective control technology for controlling NO_x emission from the Gadsby GELM6000PC turbines is water injection to reduce the amount of thermal NO_x formation and the post-combustion treatment with SCR.

4.1.4 Step 4 - Evaluate Impacts and Document Results

Water injection used in combination with SCR is the most effective and technically feasible NO_x control technology for the natural gas-fired combustion turbines at the Gadsby Power Plant. These control methods are already implemented on the combustion turbines at the Gadsby Power Plant.

Applicable BACT clearinghouse determinations were reviewed to identify NO_x emission rates achieved in practice for other simple-cycle natural gas-fired combustion turbines. The results of the review are presented in Table 4-1. From Table 4-1, when water injection is used in combination with SCR, these technologies have been demonstrated to achieve NO_x limits as low as 2.5 ppmvd at 15 percent oxygen.

Table 4-1 Summary of NO_x Emission Limits and Control Technologies for Simple-Cycle Combustion Turbines

Facility	Facility ID Number	Date of Permit	NO _x Emission Limit at 15% O ₂	Control Technology
Bayonne Energy Center, LLC	NJ-0086	8/26/2016	2.5 ppmvd 3-hr rolling average ¹	Water injection and SCR
Port Arthur LNG, LLC	TX-0790	2/17/2016	5 ppmvd 24-hr rolling average	SCR
Constellation power source generation, Inc.	MD-0043	7/1/2014	2.5 ppmvd 3-hr block average, excluding su/sd ¹	Water injection and SCR
Troutdale Energy Center, LLC	OR-0050	3/5/2014	2.5 ppmvd 3-hr rolling average on Natural Gas	Water injection and SCR
Basin Electric Power Cooperative	ND-0030	9/16/2013	5 ppmvd 4-hr rolling average except startup	SCR
Black Hills Power, Inc.	WY-0070	8/28/2012	5 ppmvd 1-hr	SCR
Black Hills Electric Generation, LLC	CO-0073	7/22/2010	5 ppmvd 1-hr average	Water injection and SCR
El Cajon Energy, LLC	CA-1174	12/11/2009	2.5 ppmvd 1-hr	Water injection and SCR
Orange Grove Project	CA-1176	12/4/2008	2.5 ppmvd 1-hr	Water injection and SCR
Escondido Energy Center, LLC	CA-1175	7/2/2008	2.5 ppmvd 1-hr	Water injection and SCR

¹LAER.

²Reduction credits use in lieu of LAER for NO_x.

4.1.4.1 Energy, Environmental, and Economic Impacts

There are energy and environmental impacts associated with the highest ranking control technology, SCR. An SCR system typically results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) also.

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through in the exhaust gas which is commonly referred to as “ammonia slip.” The ammonia that is released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. In addition, the storing of the ammonia on-site is another environmental and safety concern as well as the disposal of the catalysts in designated landfills.

4.1.5 Step 5 - Select BACM

A search of several databases was conducted to determine the most stringent control measures placed on simple-cycle turbines to achieve the lowest emission NO_x emission rate. From the RBLC database, as found under Process Type 15.110 (large gas-fired simple cycle combustion turbines), the most stringent NO_x emission rate is 2.5 part per million volume dry corrected (ppmvd). The Bay Area Air Quality Management District's (BAAQMD) BACT guideline lists 2.5 ppmvd at 15 percent oxygen accomplished by using high temperature SCR and water or steam injection.

The California Air Resources Board (CARB) BACT Clearinghouse for simple-cycle gas turbines between 2 MW and 50 MW showed several simple-cycle combustion turbines, rated between 40 and 50 MW, with the most stringent NO_x limits at 2.5 ppmvd and as high as 5 ppmvd. Three of the facilities with permit limits at 2.5 ppmvd utilize water injection and SCR for NO_x control.

The South Coast Air Quality Management District's (SCAQMD) BACT Clearinghouse has three simple-cycle gas turbine BACT determinations listed. All three units were between 40 and 50 MW and have emission limits of 5 ppmvd.

The Texas Commission on Environmental Quality's (TCEQ) current BACT requirements list gas-fired simple cycle turbines. Control technologies listed include DLN, water or steam injection in combination with SCR and have a minimum control efficiency of 5 to 9 ppmvd at 15 percent oxygen.

Utilizing pipeline quality natural gas, water injection, and SCR on the simple-cycle combustion turbines at the Gadsby Power Plant. A NO_x emission limit for each turbine of 5 ppmvd @ 15% O₂ based on a 30 day rolling average under steady state operation is currently in place for all three simple-cycle combustion turbines. This limit is supported by EPA's RACT/BACT/LAER Clearinghouse (RBLC). PacifiCorp operates continuous emissions monitoring systems (CEMs) to determine compliance with the NO_x limits. No additional limits or emissions monitoring techniques are proposed.

Most stringent measures (MSM) for simple-cycle combustion turbines using water injection and SCR is of 2.5 ppmvd at 15 percent oxygen and has been achieved in practice.

4.1.6 Step 5 - BACM for Simple Cycle Combustion Turbine Startup and Shutdown

Startup and shutdown events are a normal part of the power plant operation, but they involve NO_x emission rates that are highly variable and greater than emissions during steady-state operations. This is because the emission control systems are not fully functioning during these events. SCR and oxidation catalyst require specific exhaust temperatures ranges be reached for the control to be fully effective. When the catalyst surface temperatures are low, ammonia will not completely react with the NO_x, resulting in higher NO_x concentrations, excess ammonia slip, or both.

The principal method to limit NO_x emissions during startup and shutdown is to utilize best management practices and to minimize durations of startups and shutdowns in accordance with manufacturer's specifications.

Best management practices during a startup include ramping up the turbine to minimum load necessary to achieve compliance with the applicable NO_x emissions limits as quickly as possible. Ammonia injection is initiated to the SCR system as soon as the SCR catalyst and ammonia vaporization system have reached minimum temperature.

During a shutdown, once the turbine has been ramped down below the minimum load required to maintain NO_x emission limits, the gas turbine load should be reduced to zero as quickly as possible, consistent with manufacturer recommendations and safe operating practices. Ammonia injection to the

SCR can be maintained as long as the catalyst and ammonia vaporization system remains above the minimum operating temperature.

The only available approach to reducing startup and shutdown emissions from combustion turbines is to use best work practices. By following equipment manufacturer's recommendations, power plant operators can limit the duration of each startup and shutdown event to the minimum duration that can be achieved. Plant operators also use their operational experience with the equipment to optimize startup and shutdown.

Thus, BACT for startup and shutdown is best work practices and operating the units in accordance with manufacturer specifications and adherence to NSPS NO_x emissions standard (listed in the Title V permit) to not exceed of 116 ppm_{dv} @ 15% oxygen on a 4-hour rolling average. No technologies were identified for reducing emissions from startups and shutdowns.

4.2 Electric Generating Utility Boilers

There are three electric generators powered by natural gas-fired utility boilers (Units #1, #2, and #3). Unit #1 is comprised of a 726 MMBtu/hr boiler equipped with Low NO_x burners (LNB) and is rated at 65 MW. Unit #2 is rated at 80 MW and is powered by an 825 MMBtu/hr boiler which is also equipped with LNB. Unit #3 is rated at 105 MW and is powered by a 1,155 MMBtu/hr boiler equipped with flue gas recirculation (FGR). Each of the utility boilers may use fuel oil as a back-up fuel during natural gas curtailments.

The majority of NO_x emissions from the utility boilers will be the result of thermal NO_x formation. The rate of formation of thermal NO_x is a function of the residence time and free oxygen and is exponential with peak flame temperature. Fuel NO_x, formed through the oxidation of nitrogen in the fuel, will be present when the boilers are fired with fuel oil.

4.2.1 Step 1 - Identify All Existing and Potential Emission Control Techniques

NO_x control technologies for electric generating utility boilers fired on natural gas or fuel oil were identified through EPA's RBLC database, state and local agency databases, and literature searches. The technologies can be categorized into two types of methods; combustion controls where the amount of NO_x is controlled during the combustion process and post-combustion controls where NO_x is removed from the combustion gas stream. Combustion controls and post-combustion controls are often combined to further reduce the amount of emissions. Below is a list of control options evaluated for BACM:

1. Low NO_x Burners (LNB),
2. Ultra-low NO_x burners (ULNB),
3. External flue gas recirculation (FGR),
4. SCR,
5. SNCR,
6. EMx™,
7. Staged Air/Fuel Combustion or Overfire Air Injection (OFA),
8. Low Excess Air Firing
9. Good Combustion Practices (GCP), and
10. Use of clean burning fuels.

4.2.1.1 Low NO_x Burners

Low NO_x burner (LNB) technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a staged fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity

of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. This technique reduces the formation of thermal NO_x.

Staged fuel LNBs are well suited for boilers burning natural gas which generate higher thermal NO_x. By increasing residence times, staged-air LNBs provide reducing conditions which has a greater impact on fuel NO_x than staged fuel burners.

4.2.1.2 Ultra-Low NO_x Burners

Ultra-low NO_x burners (ULNB) may incorporate a variety of techniques including flue gas recirculation, steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and low-NO_x burner control technologies. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame impacts the amount of fuel NO_x generated.

4.2.1.3 Flue Gas Recirculation

Flue gas recirculation (FGR) is another combustion control used to reduce NO_x. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculating the hot O₂-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner wind box.

4.2.1.4 Selective Catalytic Reduction

SCR is a post-combustion technology that reacts the NO_x in the boiler exhaust with ammonia or urea and oxygen in the presence of a catalyst to form nitrogen and water. The ammonia injection grid is located upstream of the catalyst. SCR technology requires optimal gas temperatures in the range of 480°F to 800°F. NO_x conversion is sensitive to exhaust temperature and performance can be limited by contaminants in the exhaust gas that may poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream.

4.2.1.5 Selective Non-Catalytic Reduction

SNCR is a post-combustion control system that involves the injection of ammonia or urea with proprietary chemicals into the exhaust stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600°F to 2,100°F and is most commonly used in coal-fired boilers.

4.2.1.6 EM_x[™]

EM_x[™] is a catalytic oxidation and absorption control technology that uses a platinum-based oxidation catalyst coated with K₂CO₃ to oxidize and remove both NO_x, CO, and VOC without a reagent such as ammonia. NO_x reduction using EM_x[™] occurs most effectively at temperatures ranging from 300°F to 700°F. The demonstrated application for this technology is currently limited to combined cycle combustion turbines less than 50 MW and diesel-fired boilers.

4.2.1.7 Staged Air/Fuel Combustion or Over-fire Air Injection

Over-fire air (OFA) is a combustion staging processes typically used in conjunction with low NO_x burners. A portion of the combustion air is redirected from the LNB to a higher elevation in the furnace to reduce peak flame temperatures by reducing the concentration of oxygen in portions of the furnace. This technique is used to create an oxygen depleted zone where unburned hydrocarbon species act to reduce

the NO_x that was formed near the burner. The over-fire air creates an oxidation zone to complete combustion. NO_x formation is minimized by completing combustion in an air-lean environment.

4.2.1.8 Low Excess Air Firing

One factor that influences NO_x formation in a boiler is the excess air levels. High excess air levels (>45%) may increase NO_x formation because excess nitrogen and oxygen in the combustion air entering the flame will combine and form thermal NO_x. Low excess air firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra nitrogen and oxygen that enters the flame. Limiting the amount of excess air is usually accomplished through burner design and can be optimized through the use of oxygen trim controls.

4.2.1.9 Good Combustion Practices

Good combustion practices (GCP) generally includes the proper operation of the existing equipment, which includes:

1. Proper air/fuel mixing in the combustion zone;
2. High temperatures and low oxygen levels in the primary combustion zone;
3. Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency, and
4. Sufficient residence time to complete combustion. Good combustion practices is accomplished through boiler design as it relates to time, temperature, and turbulence, and boiler operation as it relates to excess oxygen levels.

4.2.1.10 Clean Burning Fuels

The utility boilers at the Gadsby Power Plant are dual-fuel boilers with each boiler exclusively burning pipeline-quality natural gas. The utility boilers are permitted to use fuel oil as a back-up fuel during natural gas curtailments and maintenance firings. Maintenance firings are limited to one percent of the total annual heat input to the boilers.

4.2.2 Step 2 - Eliminate Technically Infeasible Options

All combustion controls listed in Step 1 are widely used and have been demonstrated to control NO_x emissions from large utility boilers.

EPA's RACT/BACT/LAER Clearinghouse and state databases were searched for large utility boilers using post-construction control devices such as SNCR, SCR, and EM_x[™]. None of the databases identified facilities using EM_x[™] for large utility boilers fired on natural gas or fuel oil. EM_x[™] operates in a temperature range between 300°F to 700°F; combustion flue gas temperatures from Units #1, #2, and #3 are typically around 250°F. Since EM_x[™] has not been demonstrated in practice on large natural gas or fuel oil utility boilers and the combustion exhaust gas temperature is below the range of the control to be effective, EM_x[™] has been eliminated from further review.

All other NO_x control technologies have been demonstrated in industry and are technically feasible.

4.2.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on the results of Step 2, Table 4-2 presents the remaining control technologies have been ranked on the approximate level of emissions reduction.

Table 4-2 NO_x Control Technologies and Level of Emissions for Large Utility Boilers

Control Technology	Rate of Control (%)
ULNB + SCR	85-99%
LNB + SCR	85-95%
ULNB + SNCR	80-90%
SCR	80-90%
LNB + SNCR	55-75%
ULNB	50-80%
LNB + FGR	55-75%
LNB	35-55%
SNCR	30-50%
FGR	30-50%
Low excess air	5-10%

4.2.4 Step 4 - Evaluate Impacts and Document Results

While all the control technologies ranked in Step 3 are technically feasible, ULNB with SCR was identified as the top level of control that is technically feasible.

Several sources of information were examined including EPA's RBL CACT/BACT/LAER Clearinghouse, state agency databases, vendor data, and published literature to identify the most effective NO_x control technologies and most stringent emissions limitations to compare against current NO_x controls that have been implemented at the Gadsby Power Plant.

Table 4-3 presents a summary of BACT determinations for NO_x on industrial and utility boilers greater than 250 MMBtu/hr that are fired with natural gas or fuel oil. This table lists the lowest emission rates and control technologies utilized by facilities over the past several years.

Table 4-3 BACT Determinations for NO_x from Large Industrial and Utility Boilers with Heat Capacities Greater than 250 MMBtu/hr

Facility	Facility ID Number	Date of Permit	NO _x Emission Limit	Control Technology
Georgia Pacific Breton, LLC	AL-0271	6/11/2014	0.02 lb/MMBtu	LNB and FGR
John W. Turk Jr. Power Plant	AR-0094	11/5/2008	0.11 lb/MMBtu 30-Day Rolling Average	LNB
Montville Power, LLC	CT-0156	4/6/2010	0.06 lb/MMBtu	SCR
Port Dolphin Energy, LLC	FL-0330	12/1/2011	0.012 lb/MMBtu 3-hr Rolling Average	SCR
ADM Corn Processing - Cedar Rapids	IA-0088	6/29/2007	0.02 lb/MMBtu 30-Day Rolling Average/ Except SSM	UNLB, FGR, and GCP
Iowa Fertilizer Company	IA-0105	10/26/2012	0.0125 lb/MMBtu 30-Day Rolling Average	LNB and FGR
Cronus Chemicals, LLC	IL-0114	9/5/2014	0.012 lb/MMBtu 30-Day Rolling Average	LNB and SCR
Grain Processing Corporation	IN-0234	12/8/2015	0.05 lb/MMBtu Normal Operation	LNB and FGR
Indiana Gasification, LLC	IN-0166	6/27/2012	0.0125 lb/MMBtu 24-hr	ULNB and FGR
Spiritwood Station	ND-0024	9/14/2007	0.035 lb/MMBtu 30-Day Rolling Average	ULNB or LNB and FGR
Cargill, Incorporated	NE-0054	9/12/2013	0.04 lb/MMBtu 30-Day Rolling Average	LNB and FGR
Bayport Complex	TX-0698	9/5/2013	0.01 lb/MMBtu 3-hr Rolling Average	SCR
Chemical Manufacturing Facility	TX-0707	12/20/2013	0.01 lb/MMBtu 1-hr	SCR
Deer Park Plant	TX-0659	12/20/2013	0.01 lb/MMBtu 1-hr	SCR
Gas to Gasoline Plant	TX-0656	5/16/2014	0.01 lb/MMBtu	SCR
Utility Plant	TX-0704	12/2/2014	0.01 lb/MMBtu 3-hr Rolling Average	SCR
Appleton Coated Combined Locks Mill	WI-0244	6/19/2007	0.09 lb/MMBtu ≤50,000 lbs. Steam	LNB and FGR
Green River Soda Ash Plant	WY-0074	11/18/2013	0.011 lb/MMBtu 30-Day Rolling	LNB and FGR

This analysis includes four aspects: (1) Costs of Control, (2) Energy Impacts, (3) Non-Air Quality Environmental Impacts, and (4) Remaining Useful Life. Collateral emissions increases are presented, if applicable.

4.2.4.1 Economic Impact

An economic impact analysis was conducted to determine the cost of installing additional NO_x controls on each of the electric generating utility boilers (Units #1, #2, and #3). For the purposes of this analysis, it is assumed that each of the units will require the installation of a separate SCR or SNCR systems. It is also assumed that Units#1 and #2 will need separate installations of FGR and Unit #3 can be upgraded with LNB.

For SCR/SNCR cost estimates, methods described in EPA’s Cost Control Manual and associated SCR/SNCR Cost Calculation Spreadsheets¹ were used to estimate capital and annualized costs for installing SCR and SNCR on each utility boiler. Due to the age of the boilers and previous retrofits to convert the boilers from coal to natural gas, the retrofit difficulty factor was increased.

FGR^{2,3} and LNB⁴ cost estimates were based on literature and vendor estimates on a dollar per kilowatt estimate. Table 4-4 and Appendix A provide cost estimates (in 2016 dollars) of applying additional NO_x control to each of the utility boilers (Unit #1, #2, and #3).

Table 4-4 Cost Effectiveness of Installing NO_x Pollution Control Systems on Utility Boilers

Unit	Control Technology	Annualized Cost of Control Option	NO _x Reduction (TPY)	Cost Effectiveness (\$/Ton)
Unit #1	SNCR	\$831,415	16.22	\$51,267
Unit #1	SCR	\$2,831,487	79.18	\$35,761
Unit #1	FGR	\$258,036	19.08	\$13,524
Unit #2	SNCR	\$893,186	18.43	\$48,467
Unit #2	SCR	\$3,254,754	89.98	\$36,174
Unit #2	FGR	\$317,583	21.68	\$14,648
Unit #3	SNCR	\$1,062,143	12.65	\$83,982
Unit #3	SCR	\$4,199,066	101.18	\$41,502
Unit #3	LNB	\$1,246,674	43.72	\$28,512

As presented in Table 4-4, installation of SNCRs on each of the utility boilers is over \$48,000 per ton of NO_x removed per unit. In addition, installation of an SCR system on each of the utility boilers will cost over \$35,000 per ton of NO_x removed per unit. The cost effectiveness analysis for installing a LNB on Unit #3 shows 43.72 tons of NO_x reduced at a cost of \$28,512 per ton of NO_x removed. As such, SNCR, SCR, and LNB are considered economically infeasible for the electric generating utility boilers. Cost estimates for installing flue gas recirculation on Units #1 and #2 show a total reduction of approximately 40 tons per year at an average of \$14,086 per ton of NO_x removed.

4.2.4.2 Energy Impacts

Energy impacts of SCR, SNCR, and LNB (for Unit #3) systems on utility boilers are minimal. Flue gas recirculation systems reduce the peak temperature of the flame leading to a reduction in thermal NO_x emissions. Heat absorption in the radiant heat transfer surfaces of the boilers is also reduced with the reduction of the flame temperature reducing the thermal efficiency of the boiler. In addition to the boiler efficiency loss, FGR systems have energy costs associated with the blower fans used to circulate the air from the flue back into the combustion chamber. Flue gas recirculation can be increased to reduce NO_x emissions from the burners at the cost of boiler efficiency, flame stability, and vibration.

¹EPA Air Pollution Control Cost Manual, Section 4 Chapter 2 – Selective Catalytic Reduction (May 2016)
<https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>

²MPR Associates, Inc., *NO_x Reduction Overview*

³Entropy Technology & Environmental Consultants, Inc., *IFGR Cost Effectiveness Analysis*

⁴NESCAUM (2008), *Applicability and Feasibility of NO_x, SO₂, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*

4.2.4.3 Non-Air Quality Environmental Impacts

EPA and state databases did not identify SNCR being used on large industrial or utility boilers. Both SCR and SNCR pose adverse environmental, energy, and economic impacts. A critical problem of the SCR and SNCR processes is the generation of ammonia slip; ammonium chloride is formed when the ammonia reacts with hydrochloric acid (HCl) in the flue gas. Additionally, the use of SCR and SNCR lead to the conversion of SO₂ to SO₃ and formation of ammonium sulfate/sulfite particles that could have a serious impact on downstream components.

No environmental impacts were identified for installing FGR on Units #1 and #2 or LNB on Unit #3.

4.2.5 Step 5 - Select BACM

The BAAQMD BACT guideline lists SCR, LNB, and FGR, or ULNB with FGR as control technologies for boilers larger than 50 MMBtu that represent BACT without listing an emission limit.

The Gadsby Power Plant Units #1 and #2 utility boilers utilize LNB with emission limits in the Title V permit of 336 ppmvd at 3 percent oxygen with individual limits of 179 lb/hr (approximately 0.25 lb/MMBtu) for Unit #1 and 204 lb/hr (approximately 0.25 lb/MMBtu) for Unit #2. Unit #3 utilizes FGR with an emission limit of 168 ppmvd at 3 percent oxygen with seasonal limits of 142 lb/hr (approximately 0.12 lb/MMBtu) from November 1 through February 28(29) and 203 lb/hr (approximately 0.18 lb/MMBtu) from March 1 through October 31. The utility boilers at the Gadsby Power Plant (Units #1 through #3) operate at a no more than 25 percent of the capacity of each boiler. Currently, there are no additional cost-effective measures for reducing NO_x emissions from Unit #3. Therefore, Unit #3 operating with FGR at a capacity factor of 25 percent is considered BACT.

As can be seen in Table 4-3, several utility and industrial boilers similar in size to Gadsby Power Plant's Units #1 and #2 utilize both LNB and FGR to reduce NO_x emissions with varying degrees of emission limits up to 0.09 lb/MMBtu with one site, John W. Turk Jr. Power Plant, with an emission limit of 0.12 lb/MMBtu with only LNB. Retrofitting Units #1 and #2 with FGR may be technically feasible, however, a detailed engineering review by a vendor to determine if the boilers are capable of being retrofitted with FGR needs to be performed and was not available at the time this report was prepared.

Preliminary cost-effective analyses show installing FGR on Units #1 and #2 would reduce NO_x at an average of \$14,086 per ton. SJVAPCD and BAAQMD have established economic infeasibility thresholds of \$24,500 and \$17,500 per ton of NO_x removed in ozone and PM_{2.5} nonattainment areas, Massachusetts Department of Environmental Protection (MassDEP) has established a range of thresholds from \$11,000 to \$13,000 per ton of NO_x removed in an ozone nonattainment area.

Most stringent measures for the utility boilers would be the use of SCR on each of the boilers. However, environmental impacts from the SCR systems such as ammonia slip, catalyst disposal, as well as energy and economic impacts, as discussed in section 4.2.4.3, would be introduced.

4.3 Emergency Diesel Engines

Diesel emergency equipment at the Gadsby Power Plant consists of a 175 kW generator (EU#10) and a 1,007 kW generator (EU#25). Both units are fueled with diesel.

Diesel engines are classified as compression ignition (CI) internal combustion engines. The predominant mechanism for NO_x formation from internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air.

In diesel engines, air is drawn into a cylinder as the piston creates space for it by moving away from the intake valve. The piston's subsequent upward swing then compresses the air, heating it at the same time. Next, fuel is injected under high pressure as the piston approaches the top of its compression stroke,

spontaneously igniting as it contacts the heated air. The hot combustion gases expand, driving the piston downward. During its return swing, the piston pushes spent gases from the cylinder, and the cycle begins again with an intake of fresh air.

The predominant mechanism for NO_x formation from CI internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air.

4.3.1 Step 1 - Identify All BACM Emission Control Techniques

The following control options were evaluated for controlling NO_x emissions from the CI combustion engines. They are categorized as combustion modifications and post-combustion controls. Combustion modifications include: ignition timing retard, air-to-fuel ratio, and derating. Post combustion controls include SCR, NSCR catalyst, and NO_x absorption systems.

4.3.1.1 Ignition Timing Retard

As described above, the injection of diesel fuel into the cylinder of a CI engine initiates the combustion process. With ignition timing retard, this combustion modification lowers NO_x emissions by moving the ignition event to later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. Because the combustion chamber volume is not at its minimum, the peak flame temperature is reduced which reduces the formation of thermal NO_x.

4.3.1.2 Air-to-Fuel Ratio

Diesel engines are inherently lean-burn engines. The air-to-fuel ration can be adjusted by controlling the amount of fuel that enters each cylinder. By reducing the air-to-fuel ratio to near stoichiometric, combustion will occur under conditions of less excess oxygen and reduced combustion temperatures. Lower oxygen levels and combustion temperature reduce NO_x formation.

4.3.1.3 Derating

Derating involves restricting engine operation to lower than normal levels of power production. Derating reduces cylinder pressure and temperatures which reduces NO_x formation.

4.3.1.4 Selective Catalytic Reduction

SCR systems have two key operating variables that work together to achieve NO_x reductions. These are the exhaust temperature and the injection of urea or ammonia. The exhaust temperature must be between 260°C and 540°C for the catalyst to operate properly. SCR systems will not begin injection of ammonia in the form of urea until the catalyst has reached the minimum operating temperature. The urea is a critical component in determining the control efficiency of the SCR. It must be injected in the exhaust stream upstream of the SCR system. In the catalyst, it reacts to reduce NO_x to form N₂ and H₂O. The reaction takes place because the catalyst lowers the reaction temperature necessary for NO_x.

For SCR systems to function effectively, exhaust temperatures must be high enough (260°C to 540°C) to enable catalyst activation. For this reason, SCR control efficiencies are expected to be relatively low during the first 20 to 30 minutes after engine start up, especially during maintenance and testing. There are also complications controlling the excess ammonia (ammonia slip) from SCR use.

4.3.1.5 Non-Selective Catalytic Reduction

Non-selective catalytic reduction (NSCR) systems are used to reduce emissions from rich-burn engines that are operated stoichiometrically or fuel-rich stoichiometric. In the engine exhaust, NSCR catalysts convert NO_x to nitrogen and oxygen. NSCR catalytic reactions require that O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios. Lean-burn engines are characterized by an oxygen-rich exhaust which minimizes the potential for NO_x reduction.

4.3.1.6 NO_x Absorption Systems (Lean NO_x Traps)

NO_x absorber development is a new catalyst advance for removing NO_x in a lean (i.e., oxygen rich) exhaust environment for both diesel and gasoline lean-burn direct-injection engines.

With this technology, NO is catalytically oxidized to NO_2 and stored in an adjacent chemical trapping site as a nitrate. The stored NO_x is removed in a two-step reduction step by temporarily inducing a rich exhaust condition. NO_x absorbers (sometimes referred to as lean NO_x traps) employ precious metal catalyst sites to carry out the first NO to NO_2 conversion step. The NO_2 then is adsorbed by an adjacent alkaline earth oxide site where it chemically reacts and is stored as a nitrate. When this storage media nears capacity it must be regenerated. This is accomplished by creating a rich atmosphere with injection of a small amount of diesel fuel. The released NO_x is quickly reduced to N_2 by reaction with CO on a rhodium catalyst site or another precious metal that is also incorporated into this unique single catalyst layer.

4.3.2 Step 2 - Eliminate Technically Infeasible Options

NSCR catalysts are effective to reduce NO_x emissions when applied to rich-burn engines fired on natural gas, propane or gasoline. The diesel engines located at the Gadsby Power Plant are inherently lean-burn engines; thus, NSCR is eliminated from further consideration.

In addition, NO_x absorbers were eliminated from further consideration since NO_x absorbers are experimental technology and no commercial applications of NO_x absorbers were identified in state or EPA's RBLC RACT/BACT/LAER Clearinghouse databases as being employed on stationary emergency generators or fire pumps. Also, the literature indicates that testing of these NO_x absorbers has raised issues about sustained performance of the catalyst. Current lean NO_x catalysts are prone to poisoning by both lube oil and fuel sulfur.

4.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options, combustion modifications and the post-combustion control, SCR will be examined further. Combustion controls have been demonstrated to reduce NO_x emissions from CI engines by approximately 50%; the use of a SCR can reduce emissions in the range from 70 to 90%.

4.3.4 Step 4 - Evaluate Impacts and Document Results

The top control option, SCR, uses a reducing-agent like ammonia or urea (which is usually preferred) with a special catalyst to reduce NO_x in diesel exhaust to N_2 . The SCR catalyst sits in the exhaust stream and the reducing agent is injected into the exhaust ahead of the catalyst. Once injected the urea becomes ammonia and the chemical reduction reaction between the ammonia and NO takes place across the SCR catalyst. With the use of an SCR, there is the potential for some ammonia to "slip" through the catalyst.

SCR systems have two key operating variables that work together to achieve NO_x reductions. These are the exhaust temperature and the injection of urea or ammonia. The exhaust temperature must be between 260°C and 540°C for the catalyst to operate properly. SCR systems will not begin injection of ammonia in the form of urea until the catalyst has reached the minimum operating temperature. The urea is a critical

component in determining the control efficiency of the SCR. It must be injected in the exhaust stream upstream of the SCR system. In the catalyst, it reacts to reduce NO_x to form N₂ and H₂O. The reaction takes place because the catalyst lowers the reaction temperature necessary for NO_x.

Since SCR systems require an operating temperature between 260°C and 540°C, reaching these temperatures may be difficult in routine maintenance and testing operations where the engine is typically operated at low load for a short period of time. If the critical temperatures are not met while the engine is running, there will be no NO_x reduction benefit. To have NO_x reduction benefit, the engine would need to be operated with higher loads and for a longer period of time. This would be a challenge for PacifiCorp since each engine is limited to 50 operating hours per year.

Urea handling and maintenance must also be considered. Urea crystallization in the lines can damage the SCR system and the engine itself. Crystallization in the lines is more likely in emergency standby engines due to their periodic and low hours of usage.

4.3.4.1 Energy, Environmental, and Economic Impacts

There are several downsides with using an SCR. First, an improperly functioning SCR system can create excess ammonia emissions. SCR systems also add significant equipment to the engine system which increases the possibility of failures and increasing on-going maintenance costs. In addition, cost evaluations were performed to determine the cost of control per ton of NO_x removed from an SCR for the emergency generators. Per EPA’s cost effectiveness evaluation, costs per ton of NO_x removed are presented in Table 4-5 and in Appendix A. These values include component and installation costs of the SCR⁵.

Table 4-5 Cost Effectiveness of Installing SCR on Emergency Diesel Engines for NO_x Control

Equipment	Cost Effectiveness (\$/Ton)
175 kW (280 HP) generator - EU#10	\$36,059
1,007 kW (1350 HP) generator - EU#25	\$207,494

The cost of urea is \$1 KW and its shelf life is approximately two years. This could increase the cost of operation a SCR for emergency standby engines since the low number of annual hours of operation could lead to the expiration of the urea. The urea would have to be drained and replaced, creating an extra maintenance step and an increased cost to PacifiCorp.

Based on the economic costs to install a SCR system, the likelihood that the engine would not be at proper operating temperature for the SCR to be effective due to limited operating hours, and the extra maintenance and disposal costs if urea were used, SCR has been eliminated from further consideration.

Stationary diesel-fired IC engines are subject to 40 CFR 60, Subpart III. The rule establishes emission standards for NO_x, CO, PM, and non-methane hydrocarbon (NMHC), along with limiting SO₂ emissions through the use of lower sulfur fuel. This regulation applies to the emergency diesel generators at Gadsby. IC engine manufacturers must certify their 2007 model year and later generator engines to the emission standards established in the rule, for all pollutants, for the same model year and maximum engine power. In addition, and as required by §60.4207, beginning October 1, 2007, owners and operators of diesel-fired

⁵ Cost estimates provided by Wheeler machinery in Salt Lake City.

ICEs must use diesel fuel with a sulfur content less than or equal to 500 ppm by weight and beginning October 15, 2010, owners and operators must use diesel fuel with a sulfur content of 500 ppm.

4.3.5 Step 5 - Select BACT/BACM

Currently, California has the most aggressive emission reduction standards for diesel engines. The MSC method identified includes the use of SCR systems to reduce NO_x on diesel engines 1,000 HP or greater. SCR systems have not seen wide application on emergency standby engines less than 1,000 HP. Maine Department of Environmental Protection requires non-emergency engines to install SCR technology for NO_x control if their potential annual NO_x emissions exceed 20 tons as best available control technology.

Thus, the only control technology for the diesel emergency generators at the Gadsby Power Plant is a work practice requirement to adhere to GCP and to limit the operation of the units to required testing during non-emergency situations. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts and is considered BACM/BACT.

5.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS - SULFUR DIOXIDE

Emissions of SO₂ are entirely a function of the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO₂.

5.1 Simple-Cycle Gas Combustion Turbines

Three simple-cycle combustion turbines are operated at the Gadsby Power Plant. Each combustion turbine is fired exclusively on pipeline-quality natural gas. Typically, natural gas has only trace amounts of sulfur that is used as an odorant.

Sulfuric acid mist emissions can also form as a result of the small percentage of the SO₂ in the flue gas oxidizing to SO₃ and combines with water to form H₂SO₄.

5.1.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

There are two primary mechanisms to reduce SO₂ emissions from combustion sources which are:

1. Reduce the amount of sulfur in the fuel, and
2. Remove the sulfur from the CT exhaust gas with post-combustion control device such as flue gas desulfurization utilizing wet or dry scrubbers.

5.1.1.1 Reducing the Amount of Sulfur in Fuel

The combustion turbines located at the Gadsby Power Plant utilize pipeline-quality natural gas which has a maximum sulfur content of 0.8 percent. The use of a fuel containing low sulfur content is considered a control technology.

5.1.1.2 Wet Scrubbing

In wet scrubbers chemical reagents, usually an alkali material such as calcium in the form of lime or limestone, are mixed with water and used in the scrubber. SO₂ is absorbed by the scrubbing liquid in the scrubber and the chemicals in the water react with the SO₂ producing sulfite and sulfate compounds. The scrubbing liquid which contains the SO₂ falls to the bottom of the scrubber and enters a holding tank where chemical reactions continue to form solids from the SO₂.

5.1.1.3 Dry Scrubbing

Dry scrubbing is any scrubbing process that produces wastes with less than 5% water. The main types of dry scrubbing include spray drying, dry injection, or a combination of the two. For dry scrubbing, as flue gas flows through a scrubber, a fine mist of dissolved and partially dissolved alkalis such as lime is sprayed in the scrubber. Enough moisture is added in the process to partially saturate the flue gas, but the amount of moisture is kept low enough so that the final product remains dry. The lime slurry absorbs and reacts with the sulfur dioxide and is removed by a particulate control device.

5.1.2 Step 2 - Eliminate Technically Infeasible Options

Post-combustion devices such as wet or dry scrubbers are typically installed on coal-fired power plants that burn fuels with much higher sulfur contents. The SO₂ concentrations in the natural gas combustion exhaust gases are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective. These control technologies require much higher sulfur concentrations in the exhaust gases to be feasible as a control technology.

Thus, post-combustion SO₂ control devices, such as wet and dry scrubbing have not been achieved in practice at natural gas-fired simple-cycle turbines, and, as such, are not technically feasible.

5.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of pipeline quality natural gas is the top level of control for SO₂ and sulfuric acid mist.

5.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The use of pipeline-quality natural gas with a maximum sulfur content of 0.75 grain of sulfur per 100 standard cubic feet of natural gas as a BACT control technique for SO₂ will achieve the lowest SO₂ emission rates achieved in practice at other similar sources.

5.1.4.1 Energy, Environmental, and Economic Impacts

There are no adverse energy, environmental or cost impact associated with the use of these control technologies. Thus, no further analysis is required.

5.1.5 Step 5 - Select BACM

The use of pipeline quality natural gas and fuel sulfur limits are the only feasible SO₂ control technology for natural gas combustion sources. There are no adverse energy, environmental or cost impact associated with the use of these control technologies. There is no more stringent control technology available.

PacifiCorp uses Questar Gas pipeline quality natural gas with a sulfur limit of 20 grains/100 scf. With extremely low emission rates of SO₂ and H₂SO₄ it proposed that the use of pipeline-quality natural gas be considered BACT. In lieu of monitoring, PacifiCorp retains fuel receipts specifying the maximum amount of total sulfur to be 20 grains/100 scf or less. No additional limits or emissions monitoring techniques are proposed.

5.2 Electric Generating Utility Boilers

Sulfur dioxide (SO₂) emissions from utility boilers are a direct function of the sulfur content of the fuel that is burned. Each utility boiler (Units #1, #2, and #3) is fired on pipeline-quality natural gas. Fuel oil can be used as back-up fuel only during periods of natural gas curtailments and maintenance firings not to exceed one percent of the annual heat input to the boilers.

5.2.1 Step 1 - Identify All SO₂ BACM Emission Control Techniques

There are two primary mechanisms to reduce SO₂ emissions from combustion sources which are:

1. Reduce the amount of sulfur in the fuel, and
2. Remove the sulfur from the auxiliary boiler and/or convection heaters exhaust gases with post-combustion control device such as flue gas desulfurization utilizing wet scrubbers or dry scrubbers.

5.2.1.1 Clean Burning Fuels

The utility boilers located at the Gadsby Power Plant are exclusively burned on pipeline-quality natural gas which has a maximum sulfur content of 0.8 percent. The use of a fuel containing low sulfur content is considered a control technology.

Per Gadsby Power Plant's Title V permit, number 2 fuel oil or a lighter combination of number 1 and number 2 fuel oil burned in the boilers shall have a sulfur content no greater than 0.45% by weight. Fuel oil may only be used in the boilers during natural gas curtailments from the gas supplier and during maintenance firings between April 1 and November 30 not to exceed one percent of the annual heat input to the boilers. Due to the limited amount of fuel oil permitted for burning, SO₂ controls were only evaluated for natural gas firing.

5.2.1.2 Wet Scrubbing

Wet scrubbers utilize chemical reagents mixed with water to absorb SO₂ producing sulfite and sulfate compounds. The scrubbing liquid which contains the SO₂ falls to the bottom of the scrubber and enters a holding tank where chemical reactions continue to form solids from the SO₂.

5.2.1.3 Dry Scrubbing

Dry scrubbing methods include spray drying, dry injection, or a combination of the two. Flue gas flows through a scrubber, enough moisture is added in the process to partially saturate the flue gas. The lime slurry absorbs and reacts with the sulfur dioxide and is removed by a particulate control device.

5.2.2 Step 2 - Eliminate Technically Infeasible Options

Post-combustion devices such as wet or dry scrubbers have been applied in practice on coal or oil-fired utility boilers that burn fuels high sulfur contents.

Sulfur dioxide concentrations in the natural gas combustion exhaust gases are too low for scrubbing technologies to work effectively or to be technically feasible and cost effective when the boilers are fired on natural gas.

5.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of pipeline quality natural gas is the top level of control for SO₂ and sulfuric acid mist. Wet gas scrubbers are the highest rated control technology for controlling SO₂ from utility boilers when combusting fuel oil with SO₂ reductions greater than 90 percent while dry scrubbers can achieve 50 to 60 percent SO₂ reduction.

5.2.4 Step 4 - Evaluate Impacts and Document Results

The use of pipeline-quality natural gas with a maximum sulfur content of 0.75 grain of sulfur per 100 standard cubic feet of natural gas as a SO₂ control technique will achieve the lowest SO₂ emission rates achieved in practice at other similar sources.

The Gadsby Power Plant is permitted to fire the boilers with fuel oil during natural gas curtailments from the gas supplier and during maintenance firings between April 1 and November 30 not to exceed one percent of the annual heat input to the boilers. The sulfur content of the fuel is limited to 0.45% by weight.

Provided the limits on fuel oil consumption, total SO₂ from the utility boilers when fired on fuel oil is 14 tons per year. However, plant records show the facility has not fired the boilers on fuel oil in over 30 years but retains the permit condition if combusting fuel oil is ever needed.

5.2.4.1 Energy, Environmental, and Economic Impacts

There are several downsides to using wet or dry gas scrubbers for reducing SO₂ emissions. Flue gas in wet scrubber systems are redirected to a spray tower. Sulfur dioxide dissolves into the droplets formed by the system where it reacts with alkaline particulates. Sulfur laden droplets fall to the bottom of an absorber where it gets collected and sent to a reaction tank where the SO₂/alkali reaction is completed and formed into a neutral salt that needs to be disposed of. Dry systems use a powdered sorbent that absorbs SO₂. The dry waste is collected in particulate control equipment such as baghouses or ESPs. Both scrubber systems generate a solid waste to be disposed which increases the operating and maintenance costs. Lastly, wet and dry scrubbing systems have high capital and maintenance costs. Both systems are comparable in cost with dry scrubbing systems having a slightly lower initial capital cost. Table 5-1 presents the economic evaluation for installing and maintaining a dry scrubber system.

Table 5-1 Cost Effectiveness Analysis for SO₂ Removal from Gadsby Utility Boilers

Equipment	Wet Gas Scrubber Cost Effectiveness (\$/Ton)	Tons SO ₂ Removed	Dry Gas Scrubber Cost Effectiveness (\$/Ton)	Tons SO ₂ Removed
Unit #1	\$4,307,412	3.30	\$2,907,503	2.93
Unit #2	\$4,603,874	3.80	\$3,057,330	3.43
Unit #3	\$4,200,333	5.47	\$2,701,390	5.10

There are no adverse energy, environmental or cost impacts associated with the use of natural gas fuel and good combustion practices.

5.2.5 Step 5 - Select BACM

The use of pipeline quality natural gas and fuel sulfur limits are the only feasible SO₂ control technologies for natural gas combustion sources and is considered BACM. The utility boilers at Gadsby are dual-fuel capable with number 2 fuel oil being limited to less than one percent of the total annual heat input to the boilers.

PacifiCorp uses Questar Gas pipeline quality natural gas with a sulfur limit of 20 grains/100 scf. With extremely low emission rates of SO₂ and H₂SO₄ it proposed that the use of pipeline-quality natural gas and limiting fuel oil consumption be considered BACT. There are no more stringent measures for removing SO₂ from boilers fired on natural gas. Most stringent measures for controlling SO₂ emissions from the utility boilers would be to remove the option of firing fuel oil in the boilers. However, as previously mentioned, fuel oil has not been fired in the boilers in over 30 years. No additional limits or emissions monitoring techniques are proposed.

5.3 Emergency Diesel Engines

As previously stated, emergency equipment at the Gadsby Power Plant consists of a 175 kW generator (EU#10) and a 1,007 kW generator (EU#25), both of which are powered by diesel fuel.

Sulfur dioxide emissions occur from the reaction of various elements in the diesel fuel. Sulfur in diesel fuel oxidizes during combustion to SO₂ and sulfur trioxide (SO₃). In the presence of water vapor, these hydrolyze to H₂SO₄.

5.3.1 Step 1 - Identify All BACM Emission Control Techniques

Only one control option was found to reduce SO₂ emissions from the proposed CI combustion engines which is the use of low-sulfur diesel fuel.

5.3.2 Step 2 - Eliminate Technically Infeasible Options

The control option identified in Step 1 is technically feasible.

5.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The use of ultra-low sulfur diesel fuel containing no more than 15 parts per million by weight of sulfur is the only feasible SO₂ control technology for the emergency diesel combustion engines.

5.3.4 Step 4 - Evaluate Impacts and Document Results

Based on the emission standards of 40 CFR Part 60, Subpart IIII, the minimum standards that would meet BACT requirements for SO₂ emissions from IC engines at the Gadsby Power Plant include a maximum sulfur content of 500 ppmw and 15 ppmw or 0.0015 percent by weight.

5.3.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy, environmental or economic impacts associated with the use of ultra-low sulfur diesel fuel.

5.3.5 Step 5 - Select BACT/BACM

Emergency generators at Gadsby Power Plant will burn only ultra-low-sulfur diesel fuel with a maximum sulfur content of 15 ppmw. No more stringent control technologies were identified for control of SO₂ from emergency diesel generators. No additional limits or emissions monitoring techniques are proposed.

6.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS - PM_{2.5}

PM_{2.5} is particulate matter 2.5 microns or smaller. Sources of PM_{2.5} result from condensable hydrocarbons from incomplete combustion, trace particulate and other inert contaminants in the natural gas, fuel sulfur, dust drawn in from the ambient air, metal and carbon particles from equipment wear, and fugitive dust from abrasive blasting activities.

BACM's were evaluated for PM_{2.5} emissions for certain emission units in operation or proposed at the Gadsby Power Plant. These emission units include: combustion gas turbines, electric generating utility boilers, emergency generators, cooling towers, and abrasive blasting operations.

6.1 Simple-Cycle Gas Combustion Turbines

Three simple-cycle combustion turbines are operated at the Gadsby Power Plant. Each combustion turbine is fired exclusively on pipeline-quality natural gas and equipped with water injection system, SCR, and oxidation catalysts. Because the fuel source for the turbines is natural gas, combustion emissions are likely in the size range of PM_{2.5} or less for both filterable and condensable fractions.

6.1.1 Step 1 - Identify All PM_{2.5} BACM Emission Control Techniques

Three types of control technologies were reviewed for the reduction of PM_{2.5}. These technologies include:

1. Pre-combustion controls such as the inlet air filter;
2. Combustion controls which includes good combustion practice and clean burning fuels; and
3. Post-combustion controls such as electrostatic precipitators and baghouses.

6.1.1.1 Inlet Air Filter

To protect the turbine from contaminants in the air which can damage the CT, a turbine inlet air filter is used to filter out particulate matter 10 microns or less. There are two main types of filters – static filters and self-cleaning filters. Self-cleaning filters are cleaned by a pulse of backflow air that dislodges the layer of dust collected on the outside surface of the filter. Self-cleaning filters require less maintenance than static filters. Any particulate that passes through the inlet filter and combustion chamber will be exhausted to the atmosphere.

6.1.1.2 Good Combustion Practices

Good combustion practices ensure proper air/fuel mixing to achieve complete combustion which minimizes emissions of unburned hydrocarbons that can lead to formation of PM_{2.5}.

6.1.1.3 Clean Burning Fuels

The Gadsby Power Plant utilizes pipeline-quality natural gas which is an inherently clean fuel. Natural gas has only trace amounts of sulfur that can form particulate matter during combustion. This particulate matter can also combine with other compounds in the atmosphere after it is emitted to form secondary particulate matter such as sulfates.

6.1.1.4 Electrostatic Precipitator

An Electrostatic Precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

6.1.1.5 Fabric Filter Baghouse

Fabric filter (baghouse) systems consist of a structure containing tubular bags made of a woven fabric. A baghouse removes PM_{2.5} from the exhaust gas by drawing the dust laden air through a bank of filter tubes suspended inside a structural housing. PM_{2.5} is collected on the upstream side of the fabric. Particulates collect on the outside of filter bags that are periodically shaken to release the particulate matter into hoppers. Fabric filter baghouses are typically used in high-particulate emission producing applications.

6.1.2 Step 2 - Eliminate Technically Infeasible Options

The post-combustion controls, ESP's and baghouses, are not appropriate for use on natural gas-fired turbines because of the very low levels and small aerodynamic diameter of PM_{2.5} generated from natural gas combustion. ESP's and baghouses are typically used on solid/liquid-fuel fired or other types for sources with high PM emission concentrations. A state-by-state review as well as the EPA's RACT/BACT/LAER Clearinghouse databases was conducted to identify facilities that were using post-combustion control devices, such as ESPs and baghouses, for removal of PM_{2.5} for natural gas-fired simple-cycle power generation facilities. No facilities were identified in the search.

Since these post-combustion controls technologies have not been demonstrated in practice for use on natural gas-fired turbines, it was determined that these post-combustion control devices are technically not feasible and were eliminated from further consideration.

6.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Remaining PM_{2.5} control technologies including inlet air filters, good combustion practices, and the use of clean burning fuels such as natural gas are available, have been demonstrated commercially, and are technically feasible technologies that will be further considered for BACT.

6.1.4 Step 4 - Evaluate Impacts and Document Results

The major sources of PM_{2.5} emissions from a natural gas-fired gas turbine equipped with SCR for post-combustion control of NO_x are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and (3) PM in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{2.5} during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of PM into the exhaust stream.

6.1.4.1 Energy, Environmental, and Economic Impact

The use of good combustion practices, pipeline-quality natural gas, and inlet air filtration to control PM_{2.5} emissions is consistent with BACT for similar sources. Therefore, an assessment of the energy, environmental, and economic impacts is not necessary.

PM_{2.5} emission rates for the combustion turbines vary depending upon the experience of the turbine manufacturer, size, and the resulting available guarantees. Table 6-1 presents PM_{2.5} emission limits listed in EPA's RBLC database.

Table 6-1 Summary of PM_{2.5} Emission Limits and Control Technologies for Simple-Cycle Combustion Turbines

Facility	Facility ID Number	Date of Permit	PM _{2.5} Emission Limits	Control Technology
Pio Pico Energy Center	CA-1223	11/19/2012	0.0065 lb/MMBtu	Natural Gas
R.M. Heskett Station	ND-0028	2/22/2013	7.3 lb/hr Average of three tests	GCP
Bayonne Energy Center	NJ-0075	9/24/2009	5.0 lb/hr	Natural Gas, ULSD
PSEG Fossil, LLC	NJ-0076	10/27/2010	6.0 lb/hr Average of three tests	GCP, Natural Gas
Nacogdoches Power Electric Generating Station	TX-0764	10/14/2015	12.09 lb/hr	GCP, Natural Gas
Union Valley Energy Center	TX-0777	12/9/2015	8.6 lb/hr	GCP, Natural Gas
Constellation power source generation, Inc.	MD-0043	7/1/2014	5.0 lb/hr	GCP, Natural Gas
Troutdale Energy Center, LLC	OR-0050	3/5/2014	9.1 lb/hr 6-hr Average	Natural Gas, ULSD
Black Hills Power, Inc.	WY-0070	8/28/2012	4.0 lb/hr 3-hr Average	GCP
Black Hills Electric Generation, LLC	CO-0073	7/22/2010	6.6 lb/hr	GCP, Natural Gas

6.1.5 Selection of BACM

Inlet air filters, good combustion practices, and the use of a clean burning fuel such as natural gas are the only feasible and demonstrated control technologies for simple-cycle combustion turbines. There are no adverse energy, environmental or cost impact associated with the use of these control technologies.

No NSPS or NESHAP standard exists for PM_{2.5} emissions from combustion turbines, thus there is no floor of allowable PM_{2.5} BACT limits. Combined emissions from the three combustion turbines located at the Gadsby Plant are limited to 29.5 tons of PM₁₀ per year on a 12-month rolling basis.

Besides the use of natural gas, the most stringent measures found were the SJVAPCD requiring the use of an air inlet filter cooler and a lube oil vent coalescer to remove ambient particulate matter from the inlet air and to minimize the formation of lube oil mists. No more stringent control measures were identified besides the use of pipeline quality natural gas, air inlet filters, and proper combustion design.

The Gadsby Power Plant utilizes only pipeline quality natural gas, pre-filter and high density air inlet filters, and proper combustion design and operation which represents BACM. The emission rates for the combustion turbines vary depending upon the experience of the manufacturer, the size of turbine, and the resulting available guarantees. Gadsby's Title V permit does not contain a PM_{2.5} emission limit for the combustion turbines. No additional limits or emissions monitoring techniques are proposed.

6.2 Electric Generating Utility Boilers

The three electric generating utility boilers (Units #1, #2, and #3) utilize natural gas as the primary fuel with fuel oil only permitted during natural gas curtailments and maintenance firings. Because the primary fuel source for the utility boilers is natural gas, combustion emissions are likely in the size range of PM_{2.5} or less for both filterable and condensable fractions.

6.2.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

The following is a list of combustion and post-combustion control technologies which were identified for controlling PM_{2.5} emissions:

1. Good Combustion Practices;
2. Use of clean burning fuels;
3. Proper design and operation;
4. Wet gas scrubbers;
5. Electrostatic precipitator (ESP);
6. Cyclone; and
7. Baghouse/fabric filters.

6.2.1.1 Good Combustion Practices

Fine particulate emissions from utility boilers can be reduced by maintaining the utility boilers in good working order per manufacturer specifications.

6.2.1.2 Clean Burning Fuels

The utility boilers located at the Gadsby Power Plant are exclusively burned on pipeline-quality natural gas. Combusting natural gas exclusively with low sulfur content will reduce particulate emissions compared to other available fuels as there is less potential to form H₂SO₄. The use of a fuel containing low sulfur content is considered a control technology.

The utility boilers at the Gadsby Power Plant are permitted to fire the boilers with fuel oil during natural gas curtailments from the gas supplier and during maintenance firings between April 1 and November 30 not to exceed one percent of the annual heat input to the boilers.

6.2.1.3 Wet Gas Scrubber

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- > Sticky and/or hygroscopic materials;
- > Combustible, corrosive or explosive materials;
- > Particles that are difficult to remove in dry form;
- > PM in the presence of soluble gases; and

- > PM in gas stream with high moisture content.

6.2.1.4 Electrostatic Precipitator

ESP's are a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. Particles collected on plates are removed by knocking them loose from the plate allowing particles to fall into a hopper. Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

6.2.1.5 Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

6.2.1.6 Fabric Filter Baghouse

Fabric filter (baghouse) systems remove PM_{2.5} from exhaust gas by drawing the dust laden air through a bank of filter tubes suspended inside a structural housing. PM_{2.5} is collected on the upstream side of the fabric. Particulates collect on the outside of filter bags that are periodically shaken to release the particulate matter into hoppers. Fabric filter baghouses are typically used in high-particulate emission producing application.

6.2.2 Step 2 - Eliminate Technically Infeasible Options

Post-combustion controls are designed to capture filterable particulate in the flue gas stream. Filterable particulate emissions depend primarily on the grade of fuel fired in the combustion chamber with lighter distillates having significantly lower filterable particulate formation than heavier distillate products. The Gadsby plant is limited to combusting number two fuel oil in which condensable particulate accounting for up to forty percent of the total particulate that would not be captured in a post-combustion control.

Cyclone collection efficiency is dependent on particle size and cyclone design. Efficiency of cyclones typically increases with particle size or density, inlet duct velocity, dust loading, as well as cyclone design. Combustion of light distillate fuel oil from a boiler is not sufficient enough to meet the centrifugal force requirement to separate fine particulates from the flue gas. Thus, cyclones are considered technically infeasible and are eliminated from further evaluation.

ESP's rely on particles in the flue gas stream to acquire an electrical charge and collect onto a collector plate with an opposite electrical charge. The collector plates are then "rapped" to dislodge the particles which fall into hopper bins for disposal. Fine particulates have very slow gravitational settling; as a result, particulates dislodged from the collector plates will likely be re-entrained into the flue gas. Therefore, ESPs have been eliminated from further evaluation due to technical infeasibility.

None of the add-on post-combustion control devices (wet gas scrubber, ESP, cyclone, baghouse/fabric filters) were identified as being suitable for utility boilers burning natural gas due to the extremely low concentration of small particulates expected from combusting natural gas. However, wet scrubbers and fabric filtration (baghouses) are considered technically feasible for use with fuel oil combustion.

6.2.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Remaining technologies for controlling PM_{2.5} include fabric filter baghouses, wet gas scrubbers, and use of clean burning fuels such as natural gas with good combustion practices. Combusting natural gas in the boilers along with good combustion practices is the highest rated control option as it is inherently a clean burning fuel with very low sulfur content to limit the formation of condensable PM_{2.5}. Baghouses have the highest efficiency of removing filterable particulate from flue gas streams followed by wet gas scrubbers.

6.2.4 Step 4 - Evaluate Most Effective Controls

The major sources of PM_{2.5} emissions from the utility boilers are largely dependent on the type of fuel combusted in the burners and include the conversion of fuel sulfur to sulfates as well as unburned hydrocarbons that can lead to the formation of PM in the exhaust stack. Particulate emissions from the boilers increases when fuel oil is combusted in the burners due to impurities in the fuel oil and the sulfur content of the fuel. As previously mentioned, the Gadsby Power Plant is permitted to fire the boilers with fuel oil during natural gas curtailments from the gas supplier and during maintenance firings between April 1 and November 30 not to exceed one percent of the annual heat input to the boilers. The sulfur content of the fuel is limited to 0.45% by weight.

Provided the limits on fuel oil consumption, total particulate from the utility boilers when fired on fuel oil is less than one ton per year with filterable particulate making up less than 0.5 tons per year. In addition, plant records show the facility has not fired the boilers on fuel oil in over 30 years but retains the permit condition if combusting fuel oil is ever needed.

The use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{2.5} during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to formation of PM at the stack.

Combustion controls or “proper combustion” to minimize PM_{2.5} emissions includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. The use of clean-burning fuels, such as natural gas which has only trace amounts of sulfur that can form particulates, will result in minimal formation of PM_{2.5} during combustion. Thus, the only control technology identified in the RBLC database for the utility boilers is a work practice requirement to adhere to GCP and use of low sulfur gaseous fuels such as natural gas.

Table 6-2 presents a summary of previous BACT determinations for PM. This table is not exhaustive, rather lists the emission rates and control technologies utilized in the past few years from select plants.

Table 6-2 BACT Determinations for PM from Large Industrial and Utility Boilers with Heat Capacities Greater than 250 MMBtu/hr

Facility	Facility ID Number	Date of Permit	PM Emission Limit	Control Technology
Georgia Pacific Breton, LLC	AL-0271	6/11/2014	0.0019 lb/MMBtu	GCP
Okeelanta Cogeneration Plant	FL-0344	8/27/2013	2 Grains S/100 scf Gas	Fuel monitoring for sulfur content
Port Dolphin Energy, LLC	FL-0330	12/1/2011	0.0075 lb/MMBtu 3-hr rolling average	CBF (Natural Gas)
ADM Corn Processing - Cedar Rapids	IA-0088	6/29/2007	0.005 lb/MMBtu average of 3 test runs	CBF (Natural Gas)
Cronus Chemicals, LLC	IL-0114	9/5/2014	0.0024 lb/MMBtu 3-hr average	GCP, CBF (Natural Gas)
Indiana Gasification, LLC	IN-0166	6/27/2012	0.0075 lb/MMBtu 3-hr	CBF (Natural Gas)
Spiritwood Nitrogen Plant	ND-0032	6/20/2014	0.0067 lb/MMBtu 1-hr average	GCP
Spiritwood Station	ND-0024	9/14/2007	0.03 lb/MMBtu 3-hr (for distillate fuel)	GCP & CBF
Cargill, Inc.	NE-0054	9/12/2013	0.0075 lb/MMBtu 1-hr	GCP
Green River Soda Ash Plant	WY-0074	11/18/2013	0.007 lb/MMBtu 3-hr average	GCP

6.2.4.1 Energy, Environmental, and Economic Impacts

Adding a fabric filter baghouse or wet scrubbers to control particulate emissions from the utility boilers will have energy, environmental, and economic impacts. Baghouses are relatively high maintenance requiring periodic bag replacement which leads to additional solid waste for disposal. In addition, both baghouses and wet scrubber require a pressure drop on the flue gas stream reducing the efficiency of the unit. The efficiency of scrubbers is dependent on the pressure drop of the system and may need flue gas acceleration to remove PM_{2.5}. Wet gas scrubbers also generate effluent liquid that needs to be treated and may lead to water pollution.

Limiting fuel oil consumption is an effective measure for controlling particulate emissions from the boilers. With potential particulate emissions from the boilers being less than one ton per year when fired on fuel oil, there is no economical method for reducing PM_{2.5} emissions from the boilers.

6.2.5 Selection of BACM

The only feasible particulate control technologies identified for the three electric generating utility boilers is good combustion practices and the use of a clean burning fuel such as natural gas. There are no adverse energy, environmental, or economic impacts associated with the use of these control technologies.

The Gadsby Power Plant utilizes pipeline quality natural gas with a sulfur limit of 20 grains/100 scf. It is proposed that using pipeline-quality natural gas combined with good combustion practices and limiting the combustion of fuel oil to less than one percent of the total annual heat input to the electric generating utility boilers at the Gadsby Power Plant represents BACT.

Combined emissions listed in the in the Title V permit from the three utility boilers are limited to 44.39 tons of PM₁₀ per year on a 12-month rolling basis. Gadsby's Title V permit does not contain a PM_{2.5} emission limit for the utility boilers. No additional limits or emissions monitoring techniques are proposed.

No more stringent measures were identified for natural gas combustion. Removing the option of firing fuel oil in the boilers could be applied as a most stringent measure for reducing potential particulate emissions. However, as previously mentioned, fuel oil has not been fired in the boilers in over 30 years. No additional emissions monitoring techniques are proposed.

6.3 Emergency Diesel Engines

Diesel particulate emissions are composed of a variety of liquid phase hydrocarbons and solid phase soot (carbon). The literature suggests that the majority of particulate emissions from diesel combustion are in the PM_{2.5} size or smaller range.

6.3.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

The following control options were evaluated for controlling PM_{2.5} emissions from the CI combustion engines. They include: good combustion practiced, use of low sulfur fuels, diesel particulate filters, and diesel oxidation catalysts.

6.3.1.1 Good Combustion Practices

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators are designed to achieve maximum combustion efficiency. Manufacturers provide operation and maintenance manuals that detail the required methods to achieve the highest levels of combustion efficiency.

6.3.1.2 Ultra-Low Sulfur Diesel

Limiting the sulfur content of diesel fuel is a pollution prevention method to reduce the sulfate fraction (25%) of diesel particulate matter.

6.3.1.3 Diesel Particulate Filters

Diesel particulate filters (DPFs) are add-on devices that filter out particulate matter. In general, A DPF consists of a porous substrate that permits gases in the engine exhaust to pass through but collects or traps the diesel particulate. This is typically referred to as regenerating the DPF. During regeneration, the collected PM, which is mostly carbon, is burned off.

Particulate filters can employ either an active or passive system, depending on the method used to clean the filters. Active DPFs use a source of energy beyond the heat in the exhaust stream itself to help regeneration. Active DPFs can be regenerated electrically, with fuel burners or microwaves, or by additional fuel injection to increase exhaust temperature. Active DPFs have a broader range of application and a much lower probability of getting plugged than passive DPFs.

A passive DPF is one in which a catalytic material, typically a platinum group metal, is applied to the substrate. The catalyst lowers the temperature at which trapped particulate matter will oxidize to temperatures periodically reached in diesel exhaust. No additional energy is needed for regeneration.

6.3.1.4 Diesel Oxidation Catalyst

A diesel oxidation catalyst utilizes metal catalysts to oxidize particulate matter in the diesel exhaust. Diesel oxidation catalysts are commercially available and are reliable for reducing particulate matter emissions.

6.3.2 Step 2 - Eliminate Technically Infeasible Options

All options identified in Step 1 are technically feasible.

6.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Table 6-3 presents in descending order the control effectiveness of the identified control technologies.

Table 6-3 PM_{2.5} Control Technology Effectiveness for Diesel Engines

Control Technology	Control Effectiveness
DPF	≤85%
Oxidation Catalyst	30%
Ultra-low sulfur diesel	10-20%
GCP	Baseline

6.3.4 Step 4 - Evaluate Most Effective Controls and Document Results

The top ranked control option, diesel particulate filters can significantly reduce PM_{2.5} emissions. Typical operation of the emergency generators at the power plant include periodic testing and maintenance operations with low or no load to ensure that the engine is operating properly. For regeneration to occur on passive DPF systems, the exhaust temperature needs to be between 300°C to 465°C. To reach this temperature and for a regeneration cycle to be completed, the engine should operate for about 30 minutes at a 30 percent load.

Active DPFs are independent of temperature and will work on emergency standby engines without the same regeneration concerns presented above. The active DPF uses an electrical current or fuel combustion to remove or burn off the collected PM.

6.3.4.1 Energy, Environmental, and Economic Impacts

A cost effectiveness evaluation for the top ranking option, in costs per ton of PM_{2.5} removed, is presented in Table 6-4 and in Appendix A.

Table 6-4 Cost Effectiveness of Installing DPF on Emergency Diesel Engines for PM_{2.5} Control

Equipment	Cost Effectiveness (\$/Ton)
175 kW (280 HP) generator - EU#10	\$185,551
1,007 kW (1350 HP) generator - EU#25	\$1,067,712

Based on the economic impact presented in Table 6-4, DPF's are not cost effective for the emergency generators at the Gadsby Power Plant and have been eliminated from further consideration.

6.3.5 Step 5 - Select BACM

California has the most aggressive emission reduction standards for diesel engines. The MSC method includes the use of DPF's to reduce PM_{2.5} emissions. Several emergency standby engines were identified

operating in California that had DPF's installed on them. In most cases, however, DPFs were installed to meet permit requirements or to address odor issues. Operational considerations using active DPF's are minimal and can be accommodated by normal maintenance and testing procedures.

40 CFR 60, Subpart IIII applies to engines which commenced construction after 7/11/2005 and are manufactured after 4/1/2006 (for non-fire-pump engines), or an engine modified or reconstructed after 7/11/2005. Subpart IIII applies to the emergency diesel equipment at the power plant. Records of maintenance and hours of operation are kept. A non-resettable totalizer is installed on each emergency diesel engine.

As seen from Table 6-4, the installation of DPFs on the emergency diesel engines at Gadsby Power Plant are cost prohibitive. The use of ultra-low sulfur diesel, which will reduce PM_{2.5} emissions up to 20%, limited operating hours (100 hours per each unit), and the use of GCP is considered BACT. No additional limits or emissions monitoring techniques are proposed.

6.4 Cooling Towers

The Gadsby Power Plant has three (3) cooling water towers which serve each of the electric generating utility boilers. The cooling towers are labeled as EU#7 (serving Unit #1), EU#8 (serving Unit #2), and EU#9 (serving Unit #3). All the cooling towers are equipped with high efficiency drift eliminators.

Warm water is pumped into the top of the tower which cools as it falls downward and mixes with the rising air. The inside of the tower is filled with wooden or plastic grids so the falling water splashes and mixes with air. The water falls down into a concrete basin beneath the tower. Pumps then circulate the cool water to the units where it is used to cool hydrocarbons. Heat exchangers are used so the water does not become contaminated with the hydrocarbons. Warm water from the outlet of heat exchangers is piped back to the cooling tower, where it is cooled again.

Non-chromium based chemicals are added to the circulating water and react with water hardness to keep deposits from accumulating on the inside piping and exchangers. These chemicals also prevent algae and bacteria growth from forming inside pipes and exchangers.

6.4.1 Step 1 - Identify All Existing and Potential Emission Control Techniques

Particulate matter is emitted from wet cooling towers due to the presence of dissolved or suspended solids in water droplets from cooling tower drift. As the drifted droplet evaporates, the dissolved solids present in the droplet collected into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present, and the density of the resultant particle.

Four control technologies were identified to limit PM_{2.5} drift from cooling towers. These include:

1. Use of dry cooling heat exchanger units;
2. High-efficiency drift eliminators;
3. Limitation on total dissolved solid (TDS) concentrations in the circulating water; and
4. Combination of drift eliminator efficiency rating and TDS limit.

6.4.2 Step 2 - Eliminate Technically Infeasible Options

Dry cooling or non-evaporative cooling towers have been adopted for heat rejection at combined-cycle power plants in arid or low precipitation climates. This type of cooling tower circulates the process water through a large bank of radiator coils. These coils are cooled by forced flow of ambient air on the outer finned surfaces of the radiator. Ambient airflow is driven by very large axial propeller fans, typically located below the radiator bank, so that the air is blown upward through the radiator and the warmer air

exits the top of the tower. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, a dry cooling tower would not be a source of particulate matter emissions.

Dry cooling has been employed at primary combined-cycle power plants as a means to reduce water consumption rather than as BACT for reducing PM₁₀ emissions. There is a very substantial capital cost penalty as well as significant process changes that would be required in utilizing this control technology. Because of the high capital cost and process design changes involved in using dry cooling, and that dry cooling has not been identified as being utilized for electric generating utility boilers, this option was determined to be technically infeasible and was eliminated from further consideration.

6.4.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options were ranked in order from most to less stringent:

1. Combinations of high-efficiency drift eliminators and TDS limit;
2. High-efficiency drift eliminators to control drift as low as 0.0005% of circulating water;
3. Limitation of TDS concentrations in the circulating water.

6.4.4 Step 4 - Evaluate Impacts and Document Results

All modern cooling towers are equipped with drift eliminators. The drift eliminator forces the exhaust air to make sharp turns before exiting. The momentum of entrained droplets carries the droplets to the drift eliminators surfaces where they coalesce and drip back into the tower. Typically, for cross-flow designs the drift rate will be less than 0.005% because of the use of higher efficiency eliminators; counter-flow and forced-draft counter-flow designs routinely achieve 0.001%. In using the drift eliminators, no significant energy, environmental, or economic impacts are expected.

Incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media needs to be reduced. This is necessary to use drift eliminator media with small passages without encountering a high pressure drop. Since reducing the air velocity reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the size of the media will be needed. These changes may also result in an energy penalty in the form of larger and higher powered fans to accommodate higher drift eliminator efficiency for the same heat injection duty.

6.4.4.1 Energy, Environmental, and Economic Impacts

The drift eliminators on EU#7, EU#8, and EU#9 cooling towers at the Gadsby Power Plant have drift effectiveness of 0.002%. To upgrade to more efficient drift eliminators, high efficiency drift eliminators with a drift rate of 0.0005%, vendor cost estimates were obtained and are presented in Appendix A. A cost effectiveness evaluation for upgrading cooling towers to high efficiency drift eliminators, in costs per ton of PM_{2.5} removed, is presented in Table 6-5 and in Appendix A.

Table 6-5 Cost Effectiveness of Installing DPF on Emergency Diesel Engines for PM_{2.5} Control

Equipment	Cost Effectiveness (\$/Ton)
Unit #1 Cooling Tower (EU#7)	\$134,137
Unit #2 Cooling Tower (EU#8)	\$172,521
Unit #3 Cooling Tower (EU#9)	\$172,100

Results of the cost effectiveness analysis show the cost effectiveness, on average price per ton of PM_{2.5}, is over \$159,000 per tower. Thus, it is not economically feasible to upgrade the existing cooling towers to an ultra-low drift rate of 0.0005%.

6.4.5 Selection of BACM

The most stringent control measure (MSM) identified is the use of high efficiency drift eliminators that will meet a drift fraction rate of 0.0005%. As presented in 6.4.4.1, it is cost prohibitive to upgrade the cooling towers with more efficient drift eliminators. Thus, the cooling towers at Gadsby Power Plant are designed to minimize the potential drift and particulate emissions with a drift fraction rate of 0.002%, this is considered BACT/BACM for the Gadsby Power Plant's cooling towers. No additional limits or emissions monitoring techniques are proposed.

6.5 Abrasive Blasting

As part of the facility maintenance and upkeep activities, the Gadsby Power Plant conducts abrasive blasting to clean and prepare surfaces before painting. The Gadsby Power Plant is permitted to conduct abrasive blasting using a portable sand blaster, including two glove box units equipped with fabric filters.

Abrasive blasting systems use air pressure, centrifugal wheels, or water pressure to propel the abrasive material. The systems are typically comprised of three components: the blasting pot, propelling device, and the blasting nozzle. Abrasive materials commonly used in blasting include sand, slag, or various mineral or metallic grit products. The type of abrasive material selected is dependent on the blasting method used. There are two types of abrasive blasting techniques, wet or dry. Dry blasting is usually done using sand, various mineral or metallic shot, or other products in combination with compressed air or centrifugal force to propel the product. Wet blasting is typically conducted with sand, glass beads, or other materials that can remain suspended in water in combination with water pressure to propel the material. Particulate matter, in the form of PM₁₀, PM_{2.5}, or particulate HAPs, are the major pollutants of concern for abrasive blasting activities.

6.5.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Control methods were identified through a review of EPA and state databases, and published literature and include:

1. Fabric filter baghouses,
2. Blasting operation enclosures,
3. Vacuum blasters,
4. Drapes,
5. Water curtains,
6. Wet blasting,
7. Using low-dusting abrasives, and
8. Limit abrasive blasting operations.

6.5.1.1 Baghouse/Fabric Filter Dust Collector

See Section 6.2.1.6 for a description of a baghouse. Fabric filters from enclosed blasting operations have control efficiencies typically greater than 95%.

6.5.1.2 Blasting Operation Enclosures

Blast enclosures are designed to completely enclose one or more abrasive blast operations, thereby confining the blast debris. The enclosure floor is usually equipped with funnels to divert the captured

debris into adjacent trucks. In one design, a ventilation system is used to remove the airborne dust from the enclosure with the particles removed from the effluent airstream by a wet scrubber. The enclosures are moved as the work progresses. Blast enclosures includes shrouds, tents or other structures, which significantly restricts air contaminants from being emitted to the ambient atmosphere.

6.5.1.3 Vacuum Blaster

Vacuum blasters are designed to remove paint and other surface coatings by abrasive blasting and simultaneously collect and recover the spent abrasive and paint debris with a capture and collection system surrounding the blast nozzle. In this type of system, the abrasive is automatically reclaimed and reused as work progresses.

6.5.1.4 Drapes

Porous drapes (or curtains) on both sides of a truss-type structure (e.g., bridge) have been used to divert debris downward into a barge or lined net under the blasting operation. The top of the drapes are tied to the top of the structure.

6.5.1.5 Water Curtains

In this technique, a water header with a series of nozzles is installed along the edges of the structure being blasted. The water spray from the nozzles is directed downward creating a water curtain to collect debris from abrasive blasting performed below the header. The debris is subsequently washed down to the ground.

6.5.1.6 Wet Blasting

Wet blasting techniques include: wet abrasive blasting; high-pressure water blasting; high-pressure water and abrasive blasting; and air and water abrasive blasting. The type of wet blasting method used depends on the application. Wet abrasive blasting is accomplished by adding water to conventional abrasive blasting nozzles. High-pressure water blast systems include an engine-driven, high-pressure pump, high pressure hose, and a gun equipped with a spray nozzle. If abrasives are introduced to this type of system, high-pressure water and abrasive blasting is provided. Compared to dry blasting, all wet blasting techniques produce substantially lower dust emissions.

6.5.1.7 Low-Dust Abrasives

Low-dust abrasives are abrasives when used in sand blasting operations generate less particulate than other traditional abrasive materials.

6.5.1.8 Limiting Abrasive Blasting Operations

By limiting hours of operation for abrasive blasting operations, PM_{2.5} emissions are reduced.

6.5.2 Step 2 - Eliminate Technically Infeasible Options

Vacuum blasting, wet blasting, water curtains, and drapes are control measures typically reserved for unconfined blasting activities. At the Gadsby Power Plant, abrasive blasting activities using the portable blaster occur within a fully enclosed structure. In addition, glovebox units are fully contained chambers that route particulate formed within the chamber to fabric filters. Therefore, vacuum blasting, wet blasting, water curtains, and drapes are not appropriate for controlling blasting activities contained in enclosed structures and have been eliminated as being technically infeasible.

All remaining control technologies (baghouse/fabric filters, enclosures, and low-dust abrasives) are technically feasible.

6.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

For enclosed blasting operations, routing particulate emissions to a baghouse is the top ranked control technology with approximately 95 percent control efficiency followed by using low-dust abrasives.

6.5.4 Step 4 - Evaluate Most Effective Controls and Document Results

The top ranked control technologies for controlling particulate emissions from abrasive blasting is routing emissions to fabric filter baghouses. As previously mentioned, the glovebox units are fully contained units equipped with fabric filters. Emissions from the glovebox units are assumed to be negligible. For the portable sandblaster, all operations are conducted in a fully enclosed structure. Uncontrolled emissions for the blasting operations are less than two tons per year using uncontrolled AP-42 emission factors.

6.5.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy or environmental impacts associated with using a baghouse or low-dusting abrasive material.

Adding a fabric filter baghouse to control particulate emissions from the abrasive blasting with the portable sandblaster an economic impacts. Baghouses are relatively high maintenance requiring periodic bag replacement which leads to additional solid waste for disposal. In addition, baghouses require a pressure drop on the flue gas stream reducing the efficiency of the unit.

6.5.5 Step 5 - Selection of BACM

Maricopa County's Rule 312 states that all abrasive blasting operations shall be performed in a confined enclosure and controlling emissions by using a CARB-certified abrasive or venting to an emission control system (ECS).

CARB lists BACT for abrasive blasting as venting to a filter rated at 99.99% efficiency for 0.5 micron particles. The SCAQMD's Rule 1140 states that before blasting all abrasives used for dry unconfined blasting shall contain no more than 1% by weight material passing a No. 70 U.S. Standard sieve, and after blasting the abrasive shall not contain more than 1.8% by weight material five microns or smaller. SJVAPCD considers confined abrasive blasting to occur within a permanent structure and may require installation of a fabric filter dust collector with a minimum of 99 percent control. Clark County Department of Air Quality's Air Quality Regulations state that abrasive blasting operation will not be permitted unless effective enclosures or other such control devices have been installed to control sand and dust dispersion.

The Gadsby Power Plant glovebox units are fully contained units equipped with fabric filters with a minimum of 99 percent control. The sandblaster is used inside a building with emissions captured and routed to a dust collector. These operations occur infrequently and are associated with maintenance painting activities at the facility. There are no NSPS requirements for this source category to establish floor emission limits. Abrasive blasting within a fully enclosed building with emissions routed to a dust collector is considered BACT. No more stringent measures were identified and no additional limits or emissions monitoring techniques are proposed.

7.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS - VOLATILE ORGANIC COMPOUNDS

Unburned hydrocarbons (as VOC's) are products of incomplete combustion which occurs when there is incomplete oxidation of the carbon contained in the fuel. VOC formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, good air/fuel mixing, and adequate excess air minimize VOC emissions.

BACM's were evaluated for VOC emissions for emission units at the Gadsby Power Plant. These emission units include: combustion gas turbines, electric generating utility boilers, engines, fuel oil and lube oil storage tanks, and miscellaneous parts painting activities.

7.1 Simple-Cycle Combustion Turbines

Three simple-cycle combustion turbines are operated at the Gadsby Power Plant. Each combustion turbine is fired exclusively on pipeline-quality natural gas and equipped with water injection system, SCR, and oxidation catalysts.

As mentioned above, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing the combustion system to complete oxidize the fuel carbon to CO₂. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperature tend to reduce the formation of VOC but increase the formation of NO_x.

7.1.1 Step 1 - Identify All Existing and Potential Emission Control Technologies

Potentially available control technologies were identified based on a comprehensive review of available literature. VOC control methods are categorized into two methods: combustion controls and post-combustion control. The combustion controls for VOC formation minimize the amount of VOC formed from the combustion turbine; the post-combustion controls reduce the VOC emissions in the fuel gas stream after VOC has been formed in the combustion process. Both of these methods can be used alone or in combination to achieve various degrees of VOC control.

Several different types of emission controls were identified for this VOC BACT analysis and include:

1. Good combustion practice (GCP);
2. Oxidation catalysts;
3. EMx™; and
4. XONON.

Each control technology is described in detail below.

7.1.1.1 Good Combustion Practice

Proper combustion practices include operation of the combustion turbines at high combustion efficiencies which reduces the formation of VOC's as products of incomplete combustion. Combustion technology/design is a function of the efficient operation and design of the gas turbines. With combustion technology/design control, formation of VOC is minimized through optimum design and operation. This includes proper air-to-fuel ratios, and a turbine design that provides the necessary temperature, mixing conditions and residence time in the combustion zone.

Good combustion practice utilizes “lean combustion” where a large amount of excess air is used to produce a cooler flame temperature to minimize NO_x formation which, at the same time insures good air/fuel mixing with excess air to achieve complete combustion, thus minimizing CO emissions.

7.1.1.2 Oxidation Catalyst

An oxidation catalyst is typically a precious metal catalyst bed located in the exhaust duct. While the exhaust gas passes through the catalyst bed, oxygen and VOC migrate to the catalyst surface by gas diffusion and are adsorbed onto the catalyst active sites where oxidation then occurs. The oxidation reaction products are then desorbed from the active sites by the gas and transferred by diffusion back into the gas stream.

The control efficiency of oxidation catalyst depends on the VOC composition and concentration, operating temperature, catalyst characteristics, and the volumetric flow of exhaust gas in comparison to the volume of the catalyst. Oxidation catalyst works best at temperatures 600°F to 800°F and does not work at temperatures exceeding 1,250°F. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed the design specifications, which typically range from 700 to 50,000 standard cubic feet per minute. Sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

7.1.1.3 EM_x[™]

EM_x[™] is a catalytic oxidation and absorption control technology that uses a platinum-based oxidation catalyst coated with potassium carbonate (K₂CO₃) to oxidize and remove NO_x, CO, and VOC without a reagent such as ammonia. The EM_x[™] system reduces VOC emissions by oxidizing the VOC to CO₂. The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The EM_x[™] catalyst is susceptible to fouling by sulfur if the sulfur content of the fuel is high. This then requires the EM_x[™] catalyst to be re-coated every 6 months to 1 year, with the frequency depending on the sulfur content of the fuel.

Estimates of control efficiency for an EM_x[™] system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 80-85% for VOC emissions, although this VOC reduction is not likely to be achieved with low VOC inlet concentrations.

7.1.1.4 XONON[™]

The XONON[™] catalytic combustion system potentially can lower VOC emissions by operating at lower temperatures. XONON[™] is a catalytic combustion system that uses catalysts within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame.

7.1.2 Step 2 - Eliminate Technically Infeasible Options

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. XONON[™] has not been demonstrated on large-scale utility gas turbines with electrical output greater than 15 MW. EM_x[™] has been commercially demonstrated in five applications with no demonstrations of effectiveness on simple-cycle turbines. In addition, exhaust flue gas temperatures from the GE LM6000PC combustion turbines at the Gadsby Power Plant are approximately 825°F, which is well above the technology’s 700°F upper bound temperature to be effective.

Good combustion practices to allow the equipment to operate as efficiently as possible is available, demonstrated, and technically feasible technologies that will be further considered for BACT. Oxidation catalysts are also an available, demonstrated, and technically feasible control technology for controlling VOC emissions and will also be further considered for BACT.

7.1.3 Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The performance of an oxidation catalyst system on combustion turbines results in 30% or greater control for CO emissions. VOC control by good combustion practices is the least stringent control technology considered.

7.1.4 Step 4 - Evaluate Most Effective Controls

Applicable BACT clearinghouse determinations were reviewed to determine VOC emission rates achieved in practice for other natural gas-fired combustion turbine projects. The results of this review are presented in Table 7-1. This list is not exhaustive.

Table 7-1 Summary of VOC Emission Limits and Control Technologies for Simple-Cycle Combustion Turbines

Facility	Facility ID Number	Date of Permit	VOC Emission Limit at 15% O ₂	Control
El Cajon Energy, LLC	CA-1174	12/11/2009	2 ppmv 1-hr	Oxidation Catalyst
Escondido Energy Center, LLC	CA-1175	7/2/2008	2 ppmv @15% O ₂ 1-hr	Oxidation Catalyst
Bayonne Energy Center	NJ-0086	8/26/2016	2 ppmv @15% O ₂ 3-hr rolling average based on 1-hr block average	Oxidation Catalyst, Natural Gas
Port Arthur LNG Export Terminal	TX-0790	2/17/2016	2 ppmv 3-hr average	Oxidation Catalyst
Mountain Creek Steam Electric Station	TX-0583	1/12/2011	1.4 ppmv 3-hr rolling average	Oxidation Catalyst
Nacogdoches Power Electric Generating Plant	TX-0764	10/14/2015	2 ppmv @15% O ₂	Pipeline Quality Natural Gas; Limited Hours; Good Combustion Practices.
Neches Station	TX-0788	3/24/2016	2 ppmv	Good Combustion Practices
Cheyenne Prairie Generating Station	WY-0070	8/28/2012	3 ppmv @ 15% O ₂ 3-hr average	Oxidation Catalyst
Pueblo Airport Generating Station	CO-0073	7/22/2010	2.5 ppmvd @ 15% O ₂ average	Good Combustion Control And Catalytic Oxidation (Catox)

7.1.4.1 Energy, Environmental, and Economic Impacts

There are three potential environmental impacts with the use of an oxidation catalyst system. First, the use of an oxidation catalyst will require the replacement of the catalyst bed after several years. The waste catalyst will have to be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalyst, the oxidation catalyst may also be recycled to recover the precious metals.

A second potential environmental impact in using an oxidation catalyst to reduce VOC emissions, is that a percentage of SO₂ in the flue gas will oxidize to SO₃. The higher the operating temperature, the higher the SO₂ to SO₃ oxidation potential. The SO₃ will react with moisture in the flue gas to form H₂SO₄. The increase in H₂SO₄ emission may increase PM_{2.5} emissions.

The third potential environmental impact of using an oxidation catalyst is the oxidation of CO can result in increased CO₂ emissions. CO₂ is considered a greenhouse gas which is thought to contribute to global climate change.

The installation of an oxidation catalyst system also has an energy impact. The oxidation catalyst system located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine which results in decreased output. This decreased output will lead to increased emissions of all pollutants on a unit power output basis.

Although there are environmental and energy impacts associated with the use of an oxidation catalyst system, these impacts are not considered significant enough to preclude the use of this system for VOC control at Gadsby. Oxidation catalyst systems are currently installed on the simple-cycle combustion turbines (Units #4, #5, and #6) at the Gadsby Power Plant.

VOC emissions can be reduced by increasing the efficiency of the oxidation catalyst and reducing the emission rate from 0.0021 lb/MMBtu to 0.0018 lb/MMBtu. This would result in an annual emission reduction of approximately 1.61 tons of VOC per year. The capital costs for increasing the oxidation catalyst efficiency is estimated to be \$177,800 with an annualized cost of \$17,369 resulting in an annual cost of \$64,797 per ton of VOC removed.

7.1.5 Step 5 - Select BACM

CARB's BACT guidance document for electric generating units rated greater than 50 MW indicates that BACT for the control of VOC emissions for simple-cycle power plants is 2.0 ppmvd at 15 percent oxygen. BAAQMD's BACT guideline also lists 2.0 ppmvd at 15 percent oxygen for simple cycle gas turbines greater than 40 MW. The BACT guideline for SJVUAPCD has an achieved in practice emission limit of 2.0 ppmvd at 15 percent oxygen for gas turbines between 10 and 50 MW without heat recovery systems. SCAQMD has three simple-cycle combustion turbines permitted with VOC limits of 2.0 ppmvd at 15 percent oxygen.

Based on literature searches and data presented in Table 7-1, the highest ranking VOC control technology available for simple-cycle combustion turbines is the combination of good combustion practices and oxidation catalyst systems achieving an emission limit of 2.0 ppmvd at 15 percent oxygen. PacifiCorp is currently utilizing good combustion practices and oxidation catalyst systems on each of the simple-cycle combustion turbines located at the Gadsby Power Plant. This control methodology represents BACT for simple-cycle combustion turbines.

As seen from Table 7-1, the most stringent control is the use of an oxidation catalyst and good combustion practice with an emission limit of 1.4 ppmv. This limit, from the Mountain Creek Steam Electric Station, represents the lowest achievable emission rate (LAER) but no documentation was found to indicate this emission level was being achieved in practice. BACT for controlling VOC is being achieved on simple-cycle combustion turbines through the use of good combustion practices and oxidation catalyst systems with emission limits of 2 to 3 ppmv VOC at 15% O₂. PacifiCorp is utilizing good combustion practices and an oxidation catalyst system to control VOC emissions on each turbine located at the Gadsby Power Plant. Gadsby's Title V permit currently does not list a limit on VOC emission rates from the turbines. No additional limits or emissions monitoring techniques are being proposed.

7.2 Electric Generating Utility Boilers

Emissions of VOC's from utility boilers result from incomplete fuel combustion of carbon and organic compounds. Operating conditions such as low temperatures, insufficient residence time, and low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone result in VOC formation. VOC emissions result from incomplete combustion of the heavier molecular weight components of the fuel oil. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

7.2.1 Step 1 - Identify All VOC BACM Emission Control Techniques

Control options for VOC generally consist of fuel specifications, combustion modification measures, or post-combustion controls. Four control technologies were identified for controlling VOC emissions. These control technologies are:

- Good Combustion Practice,
- Clean Burning Fuels, and
- Catalytic Oxidation.

7.2.1.1 Good Combustion Practice

Combustion controls (proper design and operation) are the most typical means of controlling VOC emissions. Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, is essential for a low VOC emissions.

7.2.1.2 Fuel Specifications

Pipeline-quality natural gas is a fuel predominantly comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. It is processed to meet certain specifications such that key combustion parameters are relatively consistent throughout the United States. These parameters include percent methane, heating value, and sulfur content.

Distillate number 2 fuel oils have negligible nitrogen and ash content and typically contain less than 0.3 percent sulfur (by volume). Unburned hydrocarbons from fuel oil are primarily comprised of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in vapor phase at flue gas temperatures. Other organic compounds from fuel oil combustion are emitted in a condensed phase and can almost exclusively be classified as polycyclic organic matter.

7.2.1.3 Catalytic Oxidation

The formation of VOC in combustion units depends on the efficiency of combustion. Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second. The optimal range for oxidation catalysts is approximately 850 to 1,100 °F.

7.2.2 Step 2 - Eliminate Technically Infeasible Options

Only one large electric generating utility boiler was identified as using oxidation catalyst to control VOC emissions. The electric generating utility boiler is located in Connecticut and is permitted to burn natural gas, distillate fuel (with a 7% annual capacity factor), and clean wood. Several large industrial boilers were identified as using oxidation catalyst fired on natural gas, tail gas, process gas, and refinery fuel gas. The most common technologies for controlling VOC emissions from large industrial boilers was good combustion practices and using clean burning fuel. Therefore, oxidation catalyst, good combustion practices, and clean burning fuels will be further evaluated for BACM.

7.2.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The top control strategy identified for controlling VOC from large industrial boilers is oxidation catalyst. Adherence to good combustion practices is the least stringent of the VOC control technologies.

7.2.4 Step 4 - Evaluate Impacts and Document Results

Table 7-2 presents a summary of previous BACT determinations for controlling VOC from large industrial boilers. This table is not exhaustive, rather lists the lowest emission rates identified in the past several years from select plants.

As seen from Table 7-2, the most stringent emission limit is the use of oxidation catalyst with good combustion practices achieving an emission of 0.001 lb/MMBtu. This limit, from the Cove Point LNG Terminal, represents the lowest achievable emission rate (LAER). BACT for controlling VOC is being achieved on large utility and industrial boilers through the use of good combustion practices, the use of clean burning fuel, oxidation catalyst systems, or a combination of the controls to achieve emission limits in the range of 0.004 to 0.0055 lb/MMBtu VOC. PacifiCorp is utilizing good combustion practices on each of the electric generating steam utility boilers at the Gadsby Power Plant. Units #1, #2, and #3 currently do not have an emission limit for VOC.

Table 7-2 Summary of BACM Determinations for VOC for Process Large Utility and Industrial Boilers

Facility	Facility ID	Permit Date	Unit Size (MMBtu/hr)	Limit	Control Tech.
Georgia Pacific Breton, LLC	AL-0271	6/11/2014	425	0.0053 lb/MMBtu	GCP
Montville Power, LLC	CT-0156	4/6/2010	995	5.5 lb/hr (0.0055 lb/MMBtu) ¹	Oxidation Catalyst
ADM Corn Processing - Cedar Rapids	IA-0088	6/29/2007	292.5	0.0054 lb/MMBtu Average	GCP
Cronus Chemicals, LLC	IL-0114	9/5/2014	864	0.0054 lb/MMBtu 3-hr Average	GCP
Lake Charles Chemical Complex - Ethylene Unit	LA-0277	9/1/2016	418.5	3.23 lb/hr Hourly Maximum (0.0077 lb/MMBtu) ¹	GCP
Lake Charles Chemical Complex - Comonomer Unit	LA-0301	5/23/2014	662	3.63 lb/hr Hourly Maximum (0.0055 lb/MMBtu) ¹	GCP
Spiritwood Station	ND-0024	9/14/2007	281	0.005 lb/MMBtu 3-hr Average	GCP
Natgasoline, LLC	TX-0656	5/16/2014	950	14 TPY	Clean Fuel & GCP
M&G Resins Utility Plant	TX-0704	12/2/2014	450	0.004 lb/MMBtu	GCP
Ohio River Clean Fuels, LLC	OH-0317	11/20/2008	1200	13 lb/hr 3-hr Average (0.0108 lb/MMBtu) ¹	Oxidation Catalyst & GCP
Cove Point LNG Terminal	MD-0044	6/9/2014	435	0.001 lb/MMBtu 3-hr Average, Excluding SU/SD	Process Fuel Gas, Oxidation Catalyst & GCP

¹Calculated limit in lb/MMBtu from hourly emission limit (in lb/hr) and unit size (in MMBtu/hr).

7.2.4.1 Energy, Environmental, and Economic Impacts

Oxidation catalysts have traditionally been applied to control CO emissions with it being used to control VOC to a lesser extent. Oxidation catalysts have three potential environmental impacts.

First, although natural gas is the primary fuel used for the Gadsby boilers, the boilers are permitted to burn fuel oil which creates SO₂ when burned. A percentage of SO₂ in the flue gas will oxidize to SO₃ within the oxidation catalyst which will react with moisture in the flue gas to form H₂SO₄. Higher operating temperature results in higher oxidation rates of SO₂ to SO₃ resulting in higher conversion of SO₃ to H₂SO₄. The increase in H₂SO₄ emission may increase PM_{2.5} emissions. In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds.

The second environmental impact is ongoing replacement of the catalyst bed after several years. The waste catalyst will have to be disposed of in accordance with state and federal regulations regarding normal waste disposal. In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds resulting in a higher frequency of replacement. Because of the precious metal content of the catalyst, the oxidation catalyst may also be recycled to recover the precious metals.

The third potential environmental impact of using an oxidation catalyst is the oxidation of CO to CO₂ which is considered a greenhouse gas thought to contribute to global climate change.

Oxidation catalysts have a VOC reduction efficiency of approximately 30 percent. Table 7-3 presents the cost effectiveness of installing an oxidation catalyst on each of the electric generating utility boilers. Calculation spreadsheets are provided in Appendix A.

Table 7-3 Economic Analysis for Installing Oxidation Catalyst on Gadsby Electric Generating Utility Boilers

Unit	Annualized Costs of Control Option	Pollutant Removed (tons/year)	Cost Effectiveness (\$/ton)
Unit #1	\$2,042,328	1.27	\$1,605,665
Unit #1	\$2,218,327	1.45	\$1,534,749
Unit #1	\$2,428,785	2.02	\$1,200,253

¹Estimated using an annual capacity factor of 25 percent.

As can be seen in Table 7-3, the cost to add oxidation catalyst systems to the electric generating steam boilers is cost prohibitive and would remove less than 5 tons per year of VOC combined from the three units.

7.2.5 Step - Select BACM

PacifiCorp utilizes good combustion practices paired with clean burning natural gas as the primary fuel for controlling VOC emissions from the electric generating utility boilers. Fuel oil is limited to maintenance firings and natural gas curtailments and is limited to less than one percent of the plant's annual heat input requirement.

Currently, there are no limits on VOC emissions from the electric generating utility boilers at Gadsby, but the plant is using good combustion practices and firing on natural gas. This control method is comparable to other large utility and industrial boilers recently permitted and is selected as BACM for the Gadsby electric generating utility boilers (Units #1, #2, and #3). Gadsby's Title V permit currently does not list a limit on VOC emission rates from the utility boilers. No additional limits or emissions monitoring techniques are being proposed.

7.3 Diesel Emergency Engines

Diesel emergency equipment at the Gadsby Power Plant consists of a 175 kW diesel generator (EU#10) and a 1,007 kW generator (EU#25). Both of the emergency generators located at the Gadsby Power Plant are limited to operation in non-emergency situations (maintenance and readiness testing) for 50 hours per year.

VOC emissions from engines is generated as a result of incomplete combustion of the diesel fuel. These emissions occur when there is a lack of available oxygen, the combustion temperature is too low, or if the residence time in the cylinder is too short. No additional limits or emissions monitoring techniques are being proposed.

7.3.1 Step 1 - Identify All VOC BACM Emission Control Techniques

The following control options were evaluated for controlling VOC emissions from the CI internal combustion engines. They include: good combustion practices and post-combustion control technologies of diesel oxidation catalysts.

Good combustion practices refer to the operation of engines at high combustion efficiency which reduces the products of incomplete combustion. The emergency generators located at the Gadsby Power Plant are designed to achieve maximum combustion efficiency.

A diesel oxidation catalyst is a flow-through metal or ceramic substrate coated with platinum or other precious metals. The diesel oxidation catalyst sits in the exhaust stream and all exhaust from the engine passes through it. The catalyst promotes the oxidation of unburned CO and HC (as VOC) in the exhaust producing CO₂ and water. Diesel oxidation catalysts are commercially available and reliable for controlling VOC emissions from diesel engines.

7.3.2 Step 2 - Eliminate Technically Infeasible Options

The control technologies identified in Step 1 are technically feasible.

7.3.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

Combustion controls have been demonstrated to reduce VOC emissions from CI engines by approximately 50%; the use of a diesel oxidation catalyst can reduce VOC emissions in the range of 60 to 90%.

7.3.4 Step 4 - Evaluate Impacts and Document Results

Diesel oxidation catalysts can significantly reduce VOC emissions. However, due to the limited hours of proposed operation for the diesel engines, this add-on control is not practical.

7.3.4.1 Energy, Environmental, and Economic Impacts

The cost effectiveness of installing and operating standard diesel oxidation catalysts on each of the proposed engines was evaluated and presented in Table 7-4.

The cost effectiveness of an oxidation catalyst includes general maintenance, assuming proper operation of the system. If poisoning of the catalyst occurs, replacement of the catalyst will occur more frequently which increases the cost of control. In addition, engine valves/heads beyond the typical maintenance schedule will add to the maintenance costs.

Table 7-4 Cost Effectiveness of Installing DOC on Emergency Diesel Engines for VOC Control

Equipment	Cost Effectiveness (\$/Ton)
175 kW (280 HP) generator - EU#10	\$413,858
1,007 kW (1350 HP) generator - EU#25	\$2,381,456

Based on the economic impact presented in Table 7-4, DOC's are not cost effective for the emergency generators at the Gadsby Power Plant and have been eliminated from further consideration.

7.3.5 Step 5 - Select BACM

Thus, based on the economic impact, the post-combustion VOC control utilizing diesel oxidation catalysts is not cost effective for the emergency diesel engines permitted to operate 50 hours per year. Good combustion practices are currently utilized on emergency generators at the Gadsby Power Plant and engines will be maintained in accordance with manufacturer recommendations. Maintenance activities performed on the generators are subject to recordkeeping, reporting, and notification requirements defined in NESHAP Subpart ZZZZ. No additional limits or emissions monitoring techniques are being proposed.

7.4 Storage Tanks

Storage tanks are used at the Gadsby Power Plant to store distillate fuel, lube oils, water treatment chemicals, and water treatment sludge. Emissions from storage tanks result from displacement of headspace vapor during filling operations (working losses) in the case of fixed roof or internal floating roof tanks, and from diurnal temperature and heating variations (breathing losses).

Emissions from storage tanks generally include VOCs; however, tanks that store chemicals that are not hydrocarbon based (water treatment chemicals and sludge in the case for Gadsby Power Plant) are assumed to have negligible VOC emissions. Water treatment chemicals utilized at the Gadsby plant consist of aluminum sulfate, sodium hypochlorite, EDTA, and sulfuric acid. Typically, lower vapor pressure liquids such as lube oils, heating oils, diesel or kerosene are stored in fixed roof tanks; crude oils and lighter products such as gasoline are stored in floating roof tanks. Filling losses for fixed roof tanks constitute 80-90% of the total emissions.

7.4.1 Step 1 - Identify All VOC BACM Emission Control Techniques

The available control technologies for tanks storing organic liquids include control equipment designed to minimize leakage from tanks, air pollution control equipment, less polluting processes, and combinations of each. Control options that were identified include:

1. Operating the tank under pressure such that it operates with no emissions;
2. A fixed roof with vapor collection by a closed vent system routed to a control device;
3. Fixed roof in combination with an internal floating roof;
4. Fixed roof in combination with an internal roof and with a vapor collection system in a closed vent system routed to a control device;
5. An external floating roof; and
6. A fixed roof.

7.4.2 Step 2 - Eliminate Technically Infeasible Options

An effective control option, operating the tank with no emissions by operating the tank under pressure, is only feasible for tanks storing certain types of products such as compressed gases like propane and butane. The Gadsby Power Plant does not store any of these types of product and this option has been eliminated from further consideration.

External, internal or domed floating roof tanks are not utilized at the Gadsby Power Plant because the products stored at the facility (distillate fuel and lube oil) are less volatile than typical products (such as gasoline) that are stored in these type of tanks. The fuels being stored at the Gadsby Plant have vapor pressures <0.02 psia. Thus, this option and any additional control options associated with external or domes floating roof tanks have been eliminated from further consideration.

7.4.3 Steps 3 - Evaluate Control Effectiveness of Remaining Control Technologies

The remaining control options are listed in ascending order of control effectiveness:

- > Fixed roof (baseline), and
- > Fixed roof with vapor collection by a closed vent system routed to a control device.

7.4.4 Step 4 - Evaluate Impacts and Document Results

Under NSPS regulations, control equipment is required when storing volatile organic liquids with maximum vapor pressures of 0.75 psi. Otherwise, control requirements are generally triggered at 1.5 psia. As mentioned above, the fuels stored at the Gadsby Power Plant have vapor pressures <0.02 psia. Tanks storing volatile organic liquids below the vapor pressure threshold are required to keep records of the types of products stored and their vapor pressures, periods of storage and tank design specifications.

Utah Administrative Code R307-327 presents the requirements of petroleum liquid storage in ozone nonattainment and maintenance areas. R307-327-4 states (1) Any existing stationary storage tank, with a capacity greater than 40,000 gallons (150,000 liters) that is used to store volatile petroleum liquids with a true vapor pressure greater than 10.5 kilo pascals (kPa) (1.52 psia) at storage temperature shall be fitted with control equipment that will minimize vapor loss to the atmosphere. Storage tanks, except for tanks erected before January 1, 1979, which are equipped with external floating roofs, shall be fitted with an internal floating roof that shall rest on the surface of the liquid contents and shall be equipped with a closure seal or seals to close the space between the roof edge and the tank wall, or alternative equivalent controls. The owner/operator shall maintain a record of the type and maximum true vapor pressure of stored liquid. (2) The owner/operator of a petroleum liquid storage tank not subject to (1) above, but containing a petroleum liquid with a true vapor pressure greater than 7.0 kPa (1.0 psia), shall maintain records of the average monthly storage temperature, the type of liquid, throughput quantities, and the maximum true vapor pressure. None of the tanks at the Gadsby Power Plant meet the requirements of R307-327.

7.4.4.1 Energy, Environmental, and Economic Impacts

Routing vapors by a closed vent system routed to a control device is between 95-99% effective in reducing VOC emissions from storage tanks. However, the cost of a thermal oxidizer or carbon absorber would result in adverse energy and environmental impacts due to the auxiliary fuels needs for a thermal oxidizer and the additional combustion emissions (NO₂, SO₂, PM_{2.5}, and VOC) that would result from a thermal oxidizer. If activated carbon were used, a solid waste is generated that will need to be disposed of in accordance with applicable regulations.

The cost of a vapor control system is a function of the vapor flow rate to the system. The flow rate is controlled by the rate at which liquids are pumped into the tank. No facility was identified as using a vapor control system for the size of tanks that are present at the Gadsby Power Plant. Thus, the installation of a vapor control device is determined to be not economically feasible and is not BACM for the tanks at Gadsby.

7.4.5 Step 5 - Select BACM

VOC emissions from the storage tanks occur as a result of displacement of headspace during filling operations and to a lesser degree due to temperature variations and solar heating cycles. Due to the nature of the products being stored (distillate fuel and lube oil), the Gadsby Power Plant utilizes fixed roof tanks.

The Gadsby Power Plant has nine tanks permitted – a 500 gallon diesel tank, two 4,200 gallon lube oil tanks, three 975 gallon lube oil conditioner tanks, two 2,800 lube oil reservoirs, and one 3,150 lube oil reservoir. Emission from these tanks are estimated to be less than 5 pounds per year.

No economically viable options exist to control emissions from tanks permitted at the Gadsby Power Plant due to the size and low volatility of the products being stored. Thus, the proposed use of fixed roof tanks for the diesel and lube oil represents BACT.

No more stringent control measures were identified than the use of fixed roof tanks, limiting tank turnovers, for the storage of low volatile products such as distillate fuel oil and lube oil. No additional limits or emissions monitoring techniques are being proposed.

7.5 Miscellaneous Parts Painting/Paint Storage

Process equipment parts at the Gadsby Power Plant periodically have incidental preventative maintenance painting. In addition, the Gadsby Plant has various paint storage areas where sealed paint containers are kept. VOC emissions from the maintenance painting accounts for less than one ton per year.

7.5.1 Step 1 - Identify All VOC BACM Emission Control Techniques

Painting activities are classified into two categories; enclosed painting occurs in a paint booth and outdoor painting occurs in unconfined areas.

For painting in enclosed or confined quarters such as paint booths, VOC emission control technologies include:

- > Use of low VOC compliant coatings,
- > Use of high transfer efficiency application equipment,
- > Collecting and venting VOCs to an add-on control device such as a thermal oxidizer.

Thermal oxidizer, or thermal incinerator, uses a burner to destroy VOC emissions prior to release to the atmosphere through a stack. This technology includes preheating the incoming air stream to obtain additional fuel efficiencies. Time, temperature, turbulence (for mixing) and the amount of oxygen affect the rate and efficiency of the combustion process.

For outdoor (unconfined) painting, use of low VOC compliant coatings is the only control method. Other control techniques utilize good housekeeping practices for spills as well as storing coatings, solvents, and waste products in closed containers.

7.5.2 Step 2 - Eliminate Technically Infeasible Options

Collecting VOCs and venting them to a control device, such as a thermal oxidation unit, is typically reserved for large painting operations with moderate-to-high VOC loadings and is not appropriate for maintenance painting activities that occur infrequently outside with total VOC emissions of less than one ton per year. Thus, the application of this control technology to outside painting operations is not technically feasible.

All other control technologies (low VOC compliant coatings, use of high transfer efficiency application equipment, and good housekeeping practices) are technically feasible.

7.5.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

All remaining control technologies from Step 2 are equally effective.

7.5.4 Step 4 - Evaluate Impacts and Document Results

Using low VOC compliant coatings, use of high transfer efficiency application equipment, and good housekeeping are considered BACT for maintenance painting. The type of paints utilized at Gadsby include high build polyurethane products which are low VOC compliant coatings. The frequency of the painting occurs on average of 80 hours per year using approximately 200 gallons per year. VOC emissions from miscellaneous parts painting is less than one ton per year.

Utah Administrative Code R307-350 is applicable to the painting operations at Gadsby. The products used meet the VOC content limits as specified in R307-350-5.

7.5.4.1 Energy, Environmental, and Economic Impacts

There are no anticipated energy, environmental or economic impacts associated with the remaining control technologies identified for painting operations at Gadsby.

7.5.5 Step 5 - Proposed BACM

The Gadsby Power Plant uses low VOC compliant coatings, use of high transfer efficiency application equipment, and good housekeeping when conducting miscellaneous parts painting which is considered BACT. There are no NSPS, NESHAP, or MACT requirements for this source category to establish floor emission limits. No additional limits or emissions monitoring techniques are being proposed.

8.0 BEST AVAILABLE CONTROL MEASURE DETERMINATION ANALYSIS - AMMONIA

BACM's were evaluated for ammonia (NH₃) emissions from the SCR systems utilized by the combustion turbines to control NO_x emissions.

8.1 Combustion Gas Turbines

Ammonia emissions from the combustion gas turbines are a result of the ammonia slip from add-on control devices to reduce NO_x emissions such as SCR or SNCR's. Ammonia slip refers to emissions of unreacted ammonia that result from the incomplete reaction of the NO_x and the reagent.

There are two basic processes, thermal and catalytic, for using ammonia injection to control NO_x emissions from lean burn combustion equipment such as gas turbines. The thermal process, achieved by using SNCR systems, is effective only at temperatures greater than approximately 1400°F. The catalytic process, SCR operates in an optimum temperature window of approximately 650 to 850°F. In either process, some unreacted ammonia passes through to the atmosphere. This unreacted ammonia is referred to as "slip".

Typically, the amount of ammonia slip can vary from almost zero in a well-controlled stable system with moderate conversion efficiency (less than 90%) to 30 ppmv or more in systems requiring very high conversion efficiencies or in poorly controlled or highly variable systems. NO_x emissions from the Gadsby Power Plant gas combustion turbines are controlled by SCR; thus, this review will focus on ammonia slip from SCR systems.

8.1.1 Step 1 - Identify all Existing and Potential Emission Control Technologies

Ammonia emissions are result of ammonia slip from the use of ammonia-based NO_x control technologies. These technologies are discussed above, in Sections 4.1.1.1 through 4.1.1.7.

8.1.2 Step 2 - Eliminate Technically Infeasible Options

Based on the discussion above in Section 4.1.2, the remaining feasible NO_x control technologies were the use of SCR with water injection.

8.1.3 Step 3 - Evaluate Control Effectiveness of Remaining Control Technologies

SCR with water injection was the highest ranking control technology reduce NO_x emissions.

8.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The parameters of NO_x concentration, catalyst life, and ammonia slip are integrally related. Generally, catalyst performance is specified as being a particular NO_x concentration guaranteed for a certain number of years with a maximum slip concentration measured in ppm. As the catalyst degrades over time, ammonia slip will increase to not more than more than the guaranteed ammonia concentration while maintaining NO_x concentrations at or below their permitted allowance.

Applicable BACT clearinghouse determinations were reviewed to determine the NH₃ emission rates that have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review are presented in Table 8-1. This list is not exhaustive.

Table 8-1 Summary of NH₃ Emission Limits for Simple-Cycle Combustion Turbines

Facility	Facility ID Number	Date of Permit	NH ₃ Emission Limit at 15% O ₂	NO _x Control
Kleen Energy Systems, LLC	CT-0151	2/25/2008	2 ppmvd Natural Gas, Steady State Operation	LNB & SCR
Delta Power Plant	PA-0260	1/3/2008	5 ppmvd 24-hr Rolling Average	SCR
Cheyenne Prairie Generating Station	WY-0070	8/28/2012	10 ppmvd 3-hr Average	SCR

Based on Table 8-1, a few simple-cycle projects have permit limits for ammonia emissions ranging from 2 to 10 ppmvd. The single simple-cycle turbine listed in RBLC with a permit limit of 2 ppmvd is only during steady state turbine operation.

8.1.4.1 Energy, Environmental, and Economic Impacts

While there are energy, environmental, and economic impacts associated with the use of a SCR, SCR has been determined to be BACM for the reduction of NO_x emissions from the gas turbines. These impacts were determined to not be significant enough to preclude the use of SCR for NO_x emission control. Since the top control was chosen for NO_x reduction, an assessment of the energy, environmental, and economic impacts is not necessary.

8.1.5 Step 5 - Select BACT

According to SJVAPCD's web site, ammonia slip limits of 10 ppm are considered BACT for SCR-based controls. Thus, for Gadsby Power Plant, a 10 ppm ammonia limit is proposed for the simple-cycle combustion turbines. This limit is based on Gadsby's catalyst which is designed with end of life ammonia slip of 10 ppmvdc. With the originally installed reactor potential, PacifiCorp should be able to achieve guaranteed NO_x removal for the guaranteed life while not exceeding the 10 ppmvdc ammonia slip. With regular tunings, PacifiCorp should be able to meet current NO_x permit limits while not exceeding an ammonia slip of 10 ppmvdc.

As needed, catalysts are cleaned, inspected, and tested and the ammonia injection system is tuned by plant operators or an external testing organization. The rate of ammonia that is injected is based on the outlet NO_x concentrations on each combustion turbine.

Although Table 8-1 lists ammonia emission limits of 5 ppmvd, this is not considered BACM for Gadsby. BACM for ammonia at Gadsby is 10 ppm slip based on the catalyst vendor catalyst guarantee and proper operation of the SCR to achieve the permitted NO_x emission rates. No additional limits or emissions monitoring techniques are proposed.

APPENDIX A

Cost Analyses

Cost Analysis - Retrofit Emergency Diesel Engines with Diesel Particulate Filters, SCR, and Oxidation Catalysts
PacifiCorp Gadsby Power Plant

Diesel Emergency Equipment	Rating (HP)	Rating (KW)	DPF Retrofit ¹ (\$/KW)	SCR Retrofit ¹ (\$/KW)	OC Retrofit ¹ (\$/KW)	DPF Retrofit Capitol Cost	SCR Retrofit Capitol Cost	OC Retrofit Capitol Cost	Uncontrolled			Controlled			Emission Reduction			Cost Effectiveness (\$/ton)		
									PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5} PTE TPY	NO _x PTE TPY	VOC PTE TPY	PM _{2.5}	NO _x	VOC
175 kW Generator EU #10	280	175	47	350	118	\$ 8,225	\$ 61,250	\$ 20,650	0.052	1.788	0.053	0.0078	0.08940	0.0026	0.044	1.699	0.050	\$ 185,551	\$ 36,059	\$ 413,858
1,007 kW Generator EU #25	1350	1007	47	350	118	\$ 47,329	\$ 352,450	\$ 118,826	0.052	1.788	0.053	0.0078	0.08940	0.0026	0.044	1.699	0.050	\$ 1,067,712	\$ 207,494	\$ 2,381,456

Assumptions:

¹ Includes component and installation costs

Source - Discussion with Steve Loci on 3/27/2017, Wheeler Machinery, 801-974-0511

Diesel Particulate Filters - \$47/kW includes installation and labor costs

SCR - \$300 KW plus \$50 KW for installation and labor costs

Oxidation Catalysts - \$118 KW which includes installation and labor costs

Urea - \$1 KW

PTE emissions based on 50 operating hours per year and Title V permit application

DPF - 85% reduction, 95% VOC reduction

SCR - 95% NOx reduction

Assumed maintenance and labor costs to be unchanged

**Cost Analysis - Upgrading Cooling Towers from Low Efficiency Drift Eliminators to High Efficiency Drift Eliminators
PacifiCorp Gadsby Power Plant**

CT ID	Drift Eliminator		Area ft ²	30 \$/ft ² for 0.0005 % circ	Mobe/Demobe/ Shipping	Capitol Cost	Total Annual Cost ¹	PM _{2.5} Emissions	PM _{2.5} Emissions	Emission Reduction (tn/yr)	Cost Effectiveness (\$/ton)
	Dimension 1 (ft)	Dimension 2 (ft)						Before Control (tn/yr)	After Control (tn/yr)		
EU #7 (Unit #1)	51.0	217.0	11067.0	\$ 332,010	\$ 50,000	\$ 382,010	\$ 382,010	3.7972	0.9493	2.8479	\$ 134,137
EU #8 (Unit #2)	49.5	225.0	11137.5	\$ 334,125	\$ 50,000	\$ 384,125	\$ 384,125	2.9687	0.7422	2.2265	\$ 172,521
EU #9 (Unit #3)	42.0	300.0	12600.0	\$ 378,000	\$ 50,000	\$ 428,000	\$ 428,000	3.3159	0.8290	2.4869	\$ 172,100

Assumptions:

Maintenance, labor, and inspections costs would remain unchanged

Cooling tower vendor recommended \$50,000 (+/- 20%) as number to demolish and build new towers. It will be less on the smaller towers and maybe a little more on the larger towers.

Existing cooling tower have 0.002% version drift eliminators in all cooling towers

CF80's (0.0005%) run about \$30/sqft installed (quote from Cooling Tower Depot)

Cost information obtained from:

Brian S Fuqua

Regional Sales Director

Cooling Tower Depot, Inc.

517 D SE 2nd Street

Lees Summit, MO 64063

816-331-5536 Office

816-318-9493 Fax

816-585-3025 Cell

bfuqua@ctdinc.com

www.coolingtowerdepot.com



Cooling Tower Emission Estimates
PacifiCorp Gadsby Power Plant

CT ID	Circulation gal/min	TDS mg/l	Annual Hours of Operation ¹	Drift gal/min	Factor _{drift=0.002} lbs/1000 gal	PM ₁₀ Emissions (TPY)	Drift gal/min	Factor _{drift=0.0005} lbs/1000 gal	PM ₁₀ Emissions (TPY)
EU #7 (Unit #1)	70,000	4,950	2,190	0.002	0.00082566	3.797	0.0005	0.000206415	0.949
EU #8 (Unit #2)	70,000	3,870	2,190	0.002	0.000645516	2.969	0.0005	0.000161379	0.742
EU #9 (Unit #3)	82,000	3,690	2,190	0.002	0.000615492	3.316	0.0005	0.000153873	0.829

Assumptions:

Density of water: 8.34 lbs/gal

For PM10 Emissions: AP-42 5th Edition, Section 13.4 Wet Cooling Towers, Induced Drift (1/95). Emission =drift loss (lb/103 gal) *total dissolve solid (%).

¹ Based on 25% capacity factor

**NO_x Cost Analysis to Upgrade Units #1 and #2 with Flue Gas Recirculation
PacifiCorp Gadsby Power Plant**

	Unit #1	Unit #2	Factor	Basis for Cost and Factor
	FGR Upgrade	FGR Upgrade		
Direct Costs:				
Purchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$ 325,000	\$ 400,000	Estimate - \$5/kW	
Sales Tax	\$ 19,500	\$ 24,000	6% of PE	OTC-LADCO 2008
Freight	\$ 16,250	\$ 20,000	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 360,750	\$ 444,000		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$ 144,300	\$ 177,600	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 144,300	\$ 177,600		
Total Direct Cost (DC)	\$ 505,050	\$ 621,600		
Indirect Installation Costs				
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 220,058	\$ 270,840	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 220,058	\$ 270,840		
Total Installed Cost (TIC)	\$ 725,108	\$ 892,440		
NO _x Emissions Before Control, lb/MMBtu	0.12	0.12		
NO _x Emissions Before Control, tn/yr	95.40	108.41		
NO _x Emissions After Control, lb/MMBtu	0.10	0.10		
Control Efficiency (%)	20	20		
NO _x Emissions After Control, tn/yr	76.32	86.72		
NO _x Emission Reduction, tn/yr	19.08	21.68		
Annual Costs, \$/year (Direct + Indirect)				
Direct Costs				
Operating Labor	\$ 21,753	\$ 26,773	3% of Capital cost	
Replacement Parts	\$ 21,753	\$ 26,773	3% of Capital cost	
Total Direct Costs, \$/year	\$ 43,506	\$ 53,546		
Indirect Costs				
Overhead	\$ 13,052	\$ 16,064	60% of labor costs	
Efficiency/Energy Loss	\$ 54,499	\$ 67,075	\$0.0589/kW	COEN, EIA
Taxes, Insurance, and Administration	\$ 29,004	\$ 35,698	4% of total installed cost	
Capital Recovery	\$ 117,975	\$ 145,200	10%, 10 years, CRF-0.1627	
Total Indirect Costs, \$/year	\$ 214,530	\$ 264,037		
Total Annual Cost	\$ 258,036	\$ 317,583		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 13,524.43	\$ 14,648.00		

**NO_x Cost Analysis to Upgrade Units #3 with Low NO_x Burners
PacifiCorp Gadsby Power Plant**

	Unit #3	Factor	Basis for Cost
	LNB Upgrade		and Factor
Direct Costs:			
Purchased Equipment:			
Primary and Auxiliary Equipment (PE)	\$ 1,990,633	Estimate - \$1563/MMBtu	
Sales Tax	\$ 119,438	6% of PE	OTC-LADCO 2008
Freight	\$ 99,532	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 2,209,603		
Direct Installation			
Electrical, Piping, Insulation and Ductwork	\$ 883,841	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 883,841		
Total Direct Cost (DC)	\$ 3,093,444		
Indirect Installation Costs			
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 1,347,858	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 1,347,858		
Total Installed Cost (TIC)	\$ 4,441,302		
NO _x Emissions Before Control, lb/MMBtu	0.10		
NO _x Emissions Before Control, tn/yr	79.50		
NO _x Emissions After Control, lb/MMBtu	0.05		
Control Efficiency (%)	55		
NO _x Emissions After Control, tn/yr	35.77		
NO _x Emission Reduction, tn/yr	43.72		
Annual Costs, \$/year (Direct + Indirect)			
Direct Costs			
Operating Labor	\$ 133,239	3% of Capital cost	
Replacement Parts	\$ 133,239	3% of Capital cost	
Total Direct Costs, \$/year	\$ 266,478		
Indirect Costs			
Overhead	\$ 79,943	60% of labor costs	
Taxes, Insurance, and Administration	\$ 177,652	4% of total installed cost	
Capital Recovery	\$ 722,600	10%, 10 years, CRF-0.1627	
Total Indirect Costs, \$/year	\$ 980,195		
Total Annual Cost	\$ 1,246,674		
Cost Effectiveness, \$ per ton NO _x reduction	\$ 28,512.76		

**SO2 Cost Analysis to Upgrade Units #1 - #3 with Flue Gas Desulfurization - Wet Scrubber
PacifiCorp Gadsby Power Plant**

	Unit #1	Unit #2	Unit #2	Factor	Basis for Cost
	Upgrade	Upgrade	Upgrade		and Factor
Direct Costs:					
Purchased Equipment:					
Primary and Auxiliary Equipment (PE)	\$ 22,703,842	\$ 27,943,190	\$ 36,675,437		\$150/kW - 2016\$
Sales Tax	\$ 1,362,231	\$ 1,676,591	\$ 2,200,526	6% of PE	OTC-LADCO 2008
Freight	\$ 1,135,192	\$ 1,397,160	\$ 1,833,772	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 25,201,265	\$ 31,016,941	\$ 40,709,736		
Direct Installation					
Electrical, Piping, Insulation and Ductwork	\$ 10,080,506	\$ 12,406,777	\$ 16,283,894	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 10,080,506	\$ 12,406,777	\$ 16,283,894		
Total Direct Cost (DC)	\$ 35,281,771	\$ 43,423,718	\$ 56,993,630		
Indirect Installation Costs					
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 15,372,772	\$ 18,920,334	\$ 24,832,939	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 15,372,772	\$ 18,920,334	\$ 24,832,939		
Total Installed Cost (TIC)	\$ 50,654,542	\$ 62,344,052	\$ 81,826,569		
SO2 Emissions Before Control, lb/1000 gal	63.90	63.90	63.90		
SO2 Emissions Before Control, tn/yr	3.67	4.17	5.84		
SO2 Emissions After Control, lb/1000 gal	6.39	6.39	6.39		
Control Efficiency (%)	90	90	90		
SO2 Emissions After Control, tn/yr	0.37	0.37	0.37		
SO2 Emission Reduction, tn/yr	3.30	3.80	5.47		
Annual Costs, \$/year (Direct + Indirect)					
Direct Costs					
Operating Labor	\$ 1,519,636	\$ 1,870,322	\$ 2,454,797	3% of Capital cost	
Replacement Parts	\$ 1,519,636	\$ 1,870,322	\$ 2,454,797	3% of Capital cost	
Total Direct Costs, \$/year	\$ 3,039,273	\$ 3,740,643	\$ 4,909,594		
Indirect Costs					
Overhead	\$ 911,782	\$ 1,122,193	\$ 1,472,878	60% of labor costs	
Taxes, Insurance, and Administration	\$ 2,026,182	\$ 2,493,762	\$ 3,273,063	4% of total installed cost	
Capital Recovery	\$ 8,241,494	\$ 10,143,377	\$ 13,313,183	10%, 10 years, CRF-0.1627	
Total Indirect Costs, \$/year	\$ 11,179,458	\$ 13,759,332	\$ 18,059,124		
Total Annual Cost	\$ 14,218,730	\$ 17,499,975	\$ 22,968,718		
Cost Effectiveness, \$ per ton SO2 reduction	\$ 4,307,412.61	\$ 4,603,874.21	\$ 4,200,333.41		

**SO2 Cost Analysis to Upgrade Units #1 - #3 with Flue Gas Desulfurization - Dry Scrubber
PacifiCorp Gadsby Power Plant**

	Unit #1	Unit #2	Unit #2	Factor	Basis for Cost
	Upgrade	Upgrade	Upgrade		and Factor
Direct Costs:					
Purchased Equipment:					
Primary and Auxiliary Equipment (PE)	\$ 13,622,305	\$ 16,765,914	\$ 22,005,262		\$150/kW - 2016\$
Sales Tax	\$ 817,338	\$ 1,005,955	\$ 1,320,316	6% of PE	OTC-LADCO 2008
Freight	\$ 681,115	\$ 838,296	\$ 1,100,263	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$ 15,120,759	\$ 18,610,165	\$ 24,425,841		
Direct Installation					
Electrical, Piping, Insulation and Ductwork	\$ 6,048,304	\$ 7,444,066	\$ 9,770,337	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$ 6,048,304	\$ 7,444,066	\$ 9,770,337		
Total Direct Cost (DC)	\$ 21,169,063	\$ 26,054,231	\$ 34,196,178		
Indirect Installation Costs					
Engineering and Project Management, Construction and Field Expenses, Contractor Fees, Startup Expenses, Performance Tests, Contingencies	\$ 9,223,663	\$ 11,352,201	\$ 14,899,763	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$ 9,223,663	\$ 11,352,201	\$ 14,899,763		
Total Installed Cost (TIC)	\$ 30,392,725	\$ 37,406,431	\$ 49,095,941		
SO2 Emissions Before Control, lb/1000 gal	63.90	63.90	63.90		
SO2 Emissions Before Control, tn/yr	3.67	4.17	5.84		
SO2 Emissions After Control, lb/1000 gal	12.78	12.78	12.78		
Control Efficiency (%)	80	80	80		
SO2 Emissions After Control, tn/yr	0.73	0.73	0.73		
SO2 Emission Reduction, tn/yr	2.93	3.43	5.10		
Annual Costs, \$/year (Direct + Indirect)					
Direct Costs					
Operating Labor	\$ 911,782	\$ 1,122,193	\$ 1,472,878	3% of Capital cost	
Replacement Parts	\$ 911,782	\$ 1,122,193	\$ 1,472,878	3% of Capital cost	
Total Direct Costs, \$/year	\$ 1,823,564	\$ 2,244,386	\$ 2,945,756		
Indirect Costs					
Overhead	\$ 547,069	\$ 673,316	\$ 883,727	60% of labor costs	
Taxes, Insurance, and Administration	\$ 1,215,709	\$ 1,496,257	\$ 1,963,838	4% of total installed cost	
Capital Recovery	\$ 4,944,896	\$ 6,086,026	\$ 7,987,910	10%, 10 years, CRF-0.1627	
Total Indirect Costs, \$/year	\$ 6,707,675	\$ 8,255,599	\$ 10,835,474		
Total Annual Cost	\$ 8,531,238	\$ 10,499,985	\$ 13,781,231		
Cost Effectiveness, \$ per ton SO2 reduction	\$ 2,907,503.51	\$ 3,057,330.06	\$ 2,701,390.90		

VOC Cost Analysis to Upgrade Units #1 - #3 with Oxidation Catalyst
PacifiCorp Gadsby Power Plant

	Unit #1	Unit #2	Unit #2	Factor	Basis for Cost
	Upgrade	Upgrade	Upgrade		and Factor
Direct Costs:					
Total Installed Cost (TIC)	\$ 7,275,840	\$ 7,902,840	\$ 8,652,600	\$22/scfm	[EPA-452/F-03-018]
VOC Emissions Before Control, lb/MMBtu	0.0055	0.0055	0.0055		
VOC Emissions Before Control, tn/yr	4.37	4.97	6.96		
VOC Emissions After Control, lb/MMBtu	0.0039	0.0039	0.0039		
Control Efficiency (%)	29	29	29		
VOC Emissions After Control, tn/yr	3.10	3.52	4.93		
VOC Emission Reduction, tn/yr	1.27	1.45	2.02		
Annual Costs, \$/year (Direct + Indirect)					
Direct Costs					
Operating Labor	\$ 218,275	\$ 237,085	\$ 259,578	3%	of Capital cost
Replacement Parts	\$ 218,275	\$ 237,085	\$ 259,578	3%	of Capital cost
Total Direct Costs, \$/year	\$ 436,550	\$ 474,170	\$ 519,156		
Indirect Costs					
Overhead	\$ 130,965	\$ 142,251	\$ 155,747	60%	of labor costs
Taxes, Insurance, and Administration	\$ 291,034	\$ 316,114	\$ 346,104	4%	of total installed cost
Capital Recovery	\$ 1,183,779	\$ 1,285,792	\$ 1,407,778	10%, 10 years,	CRF-0.1627
Total Indirect Costs, \$/year	\$ 1,605,778	\$ 1,744,157	\$ 1,909,629		
Total Annual Cost	\$ 2,042,328	\$ 2,218,327	\$ 2,428,785		
Cost Effectiveness, \$ per ton VOC reduction	\$ 1,605,664.59	\$ 1,534,749.68	\$ 1,200,253.42		

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates ($\pm 30\%$) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

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. * NOTE: You must document why a retrofit factor of 1.15 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

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

What is the estimated actual annual MW output?

Enter the net plant heat input rate (NPHR)

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 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 burning 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.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.31	8,730
Lignite	0	0.91	6,534

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

For coal-fired boilers, 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 boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{xin}) to SCR	0.12 lb/MMBtu
NO _x Removal Efficiency (EF) provided by vendor	83 percent
Stoichiometric Ratio Factor (SRF)	1.050

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

Estimated operating life of the catalyst ($t_{catalyst}$)	24,000 hours
Estimated SCR equipment life	10 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

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

Select the reagent used

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Gas temperature at the SCR inlet (T)	258 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	455.5 ft ³ /min-MMBtu/hour

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Reagent (Cost _{reag})	3.56 \$/gallon for a 29 percent solution of ammonia		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Catalyst cost (CC _{replace})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)*		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* \$3.56/gallon is a default value for the reagent cost. User should enter actual value, if known.

* \$160/cf is a default value for the catalyst cost. User should enter actual value, if known.

* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 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)	3.56	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	0.037 - Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the 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/ .	
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)
Catalyst Cost (\$/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

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) =	$Bmw \times NPHR =$	726	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	569,400	MW/year
Estimated Actual Annual MW Output (Boutput) =		142,350	MW/year
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.12	
Total System Capacity Factor (CF_{total}) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.25	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	2190	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	83.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_b =$	72.31	lb/hour
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_b \times t_{op})/2000 =$	79.18	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.04	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_b \times (460 + T)/(460 + 700)_{n_{scr}} =$	204,704	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	12.56	/hour
Residence Time	$1/V_{space} =$	0.08	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 =	$(\%S/100) \times (64/32) \times 1E6/HHV =$		
Elevation Factor (ELEVF) =	$14.7\ psia/P =$	1.17	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{6.256} \times (1/144)^* =$	12.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.15	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightssystemsgrc.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 $Y = H_{catalyst}/(t_{scr} \times 24\ hours)$ rounded to the nearest integer	0.311	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_b \times EF_{adj} \times Slipadj \times Noxadj \times Sadj \times (Tadj/Nscr) =$	16,297.53	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}/(16\ ft/sec \times 60\ sec/min) =$	213	ft ²
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1 =$	26	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst} =$	245	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5} =$	15.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7\ ft + h_{layer}) + 9\ ft =$	143	feet

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SFR} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NO}_x} =$	28	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	97	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	13	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	4,349	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	381.73	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

$$TCI = 60,670 \times B_{MW} \times ELEV \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,270 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 9,760 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,275 \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,082 \times Q_B \times ELEV \times RF$$

Total Capital Investment (TCI) =

\$9,747,469

in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$450,957 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$1,391,033 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$1,841,991 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$48,737 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$100,922 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$30,931 in 2016 dollars
Annual Catalyst Replacement Cost =		\$270,367 in 2016 dollars
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$450,957 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$3,213 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$1,387,820 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$1,391,033 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$1,841,991 per year in 2016 dollars
NOx Removed =	79.18 tons/year
Cost Effectiveness =	\$23,264 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the *SNCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. * NOTE: You must document why a retrofit factor of 1.15 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

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

What is the estimated actual annual MW output?

Is the boiler a fluid-bed boiler?

Enter the net plant heat input rate (NPHR)

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight
or
Select the appropriate SO₂ emission rate:

Ash content (%Ash): 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, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	0	0.31	5.8	8,730	2.04
Lignite	0	0.91	14.3	6,534	1.85

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	4240 Feet above sea level
Inlet NO _x Emissions (NO _{x,in}) to SNCR	0.12 lb/MMBtu		
NO _x Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	17 percent		
Estimated Normalized Stoichiometric Ratio (NSR)	1.05		*The NSR value of 1.05 is a default value. User should enter actual value, if known.
Concentration of reagent as stored (C_{stored})	50 percent*		*The reagent concentration of 50% is a default value. User should enter actual value, if known.
Denisty of reagent as stored (ρ_{stored})	71 lb/ft ³		
Concentration of reagent injected (C_{inj})	50 percent		
Number of days reagent is stored ($t_{storage}$)	14 days		
Estimated equipment life	10 Years		
Select the reagent used	Ammonia		

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Fuel (Cost _{fuel})	3.82 \$/MMBtu		
Reagent (Cost _{reag})	1.62 \$/gallon for a 50 percent solution of ammonia*		
Water (Cost _{water})	0.0088 \$/gallon*		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Ash Disposal (for coal-fired boilers only) (Cost _{ash})	\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, 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) =	0.015
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	\$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost (\$/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	0.037 - Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .
Fuel Cost (\$/MMBtu)	5.14	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the 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/ .	3.822 based 2016 fuel cost data for Gadsby from data reported to the U.S. Energy Information Administration (EIA) on EIA Form EIA-923, Available at http://www.eia.gov/electricity/data/eia923/ .
Ash Disposal Cost (\$/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)

SNCR Design Parameters

The following design parameters for the SNCR 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) =	$B_{mw} \times NPHR =$	726	MMBtu/hour
Maximum Annual MW Output (B_{mw}) =	$B_{mw} \times 8760 =$	569,400	MW/year
Estimated Actual Annual MW Output (Boutput) =		142,350	MW/year
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.12	
Total System Capacity Factor (CF_{total}) =	$(Boutput/B_{mw}) \times (tsnrcr/365) =$	0.25	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	2190	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	17.00	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_b =$	14.81	lb/hour
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_b \times t_{op})/2000 =$	16.22	tons/year
Coal Factor ($Coal_f$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1E6 / HHV =$		
Elevation Factor (ELEVf) =	$14.7 \text{ psia}/P =$	1.17	
Atmospheric pressure at 4240 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7) / 518.6]^{5.256} \times (1/144)^*$ =	12.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.15	

Not applicable; factor applies only to coal-fired boilers

Not applicable; factor applies only to coal-fired boilers

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

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x_{\text{in}}} \times Q_{\text{G}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NO}_x} \times \text{SR}) =$ (where SR = 1 for NH_3 ; 2 for Urea)	34	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	68	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	7	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	2,397	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times \text{NO}_{x_{\text{in}}} \times \text{NSR} \times Q_{\text{G}}) / \text{NPHR} =$	3.85	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.03	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1\text{E}6) / \text{HHV} =$	0.00	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,124,497 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,264,797 in 2016 dollars
Total Capital Investment (TCI) =	\$3,106,083 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_b \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_b/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,124,497 in 2016 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_b \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_b)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_b/NPHR)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	\$1,264,797 in 2016 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$72,472 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$443,634 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$516,106 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$46,591 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$25,314 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$312 in 2016 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2016 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$255 in 2016 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2016 dollars
Direct Annual Cost =		\$72,472 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,398 in 2016 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$442,236 in 2016 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$443,634 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$516,106 per year in 2016 dollars
NOx Removed =	16.22 tons/year
Cost Effectiveness =	\$31,824 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates ($\pm 30\%$) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility What type of fuel does the unit burn? Natural Gas

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

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.15 * NOTE: You must document why a retrofit factor of 1.15 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 80 MW

What is the higher heating value (HHV) of the fuel? 1,050 Btu/scf

What is the estimated actual annual MW output? 175,200 MW/year

Enter the net plant heat input rate (NPHR) 10.31 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 4240 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units burning 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.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.31	8,730
Lignite	0	0.91	6,534

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

For coal-fired boilers, 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 boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{xin}) to SCR	0.12 lb/MMBtu
NO _x Removal Efficiency (EF) provided by vendor	83 percent
Stoichiometric Ratio Factor (SRF)	1.050

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

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	10 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

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

Select the reagent used

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Gas temperature at the SCR inlet (T)	244 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	422.6 ft ³ /min-MMBtu/hour

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Reagent (Cost _{reag})	3.56 \$/gallon for a 29 percent solution of ammonia		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Catalyst cost (CC _{replace})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)*		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* \$3.56/gallon is a default value for the reagent cost. User should enter actual value, if known.

* \$160/cf is a default value for the catalyst cost. User should enter actual value, if known.

* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 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)	3.56	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the 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/ .	
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)
Catalyst Cost (\$/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

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 _h) =	Bmw x NPHR =	825	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	700,800	MW/year
Estimated Actual Annual MW Output (Boutput) =		175,200	MW/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.03	
Total System Capacity Factor (CF _{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.25	fraction
Total operating time for the SCR (t _{op}) =	CF _{total} x 8760 =	2190	hours
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	83.0	percent
NOx removed per hour =	NOxin x EF x Q _B =	82.17	lb/hour
Total NO _x removed per year =	(NOxin x EF x Q _B x t _{op})/2000 =	89.98	tons/year
NOx removal factor (NRF) =	EF/80	1.04	
Volumetric flue gas flow rate (q _{flue gas}) =	Q _{fuel} x Q _B x (460 + T)/(460 + 700) _{n_{scr}}	211,597	acfm
Space velocity (V _{space}) =	q _{flue gas} /Vol _{catalyst}	10.86	/hour
Residence Time	1/V _{space}	0.09	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)*1E6)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =	1.17	
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6] ^{6.256} x (1/144)* =	12.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.15	

Not applicable; factor applies only to coal-fired boilers

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

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)/(1+interest rate) ^Y -1, where Y = H _{catalyst} /(t _{scr} x 24 hours) rounded to the nearest integer	0.311	Fraction
Catalyst volume (Vol _{catalyst}) =	2.81 x Q _B x EF _{adj} x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	19,492.84	Cubic feet
Cross sectional area of the catalyst (A _{catalyst}) =	q _{flue gas} /(16ft/sec x 60 sec/min)	220	ft ²
Height of each catalyst layer (H _{layer}) =	(Vol _{catalyst} /(R _{layer} x A _{catalyst})) + 1	30	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A _{SCR}) =	1.15 x A _{catalyst}	253	ft ²
Reactor length and width dimensions for a square reactor =	(A _{SCR}) ^{0.5}	15.9	feet
Reactor height =	(R _{layer} + R _{empty}) x (7ft + h _{layer}) + 9ft	159	feet

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SFR} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NOx}} =$	32	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	110	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	15	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	4,943	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	453.97	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

$$TCI = 60,670 \times B_{MW} \times ELEV \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,270 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 9,760 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,275 \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,082 \times Q_B \times ELEV \times RF$$

Total Capital Investment (TCI) =

\$11,155,953

in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$530,624 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$1,591,654 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,122,278 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$55,780 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$114,684 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$36,785 in 2016 dollars
Annual Catalyst Replacement Cost =		\$323,375 in 2016 dollars
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$530,624 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$3,297 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$1,588,357 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$1,591,654 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$2,122,278 per year in 2016 dollars
NOx Removed =	89.98 tons/year
Cost Effectiveness =	\$23,587 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the *SNCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. * NOTE: You must document why a retrofit factor of 1.15 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

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

What is the estimated actual annual MW output?

Is the boiler a fluid-bed boiler?

Enter the net plant heat input rate (NPHR)

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight
or
Select the appropriate SO₂ emission rate:

Ash content (%Ash): 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, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	0	0.31	5.8	8,730	2.04
Lignite	0	0.91	14.3	6,534	1.85

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	4240 Feet above sea level
Inlet NO _x Emissions (NO _{x,in}) to SNCR	0.12 lb/MMBtu		
NO _x Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	17 percent		
Estimated Normalized Stoichiometric Ratio (NSR)	1.05		*The NSR value of 1.05 is a default value. User should enter actual value, if known.
Concentration of reagent as stored (C_{stored})	50 percent*		*The reagent concentration of 50% is a default value. User should enter actual value, if known.
Density of reagent as stored (ρ_{stored})	71 lb/ft ³		
Concentration of reagent injected (C_{inj})	50 percent		
Number of days reagent is stored ($t_{storage}$)	14 days		
Estimated equipment life	10 Years		
Select the reagent used	Ammonia		

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Fuel (Cost _{fuel})	3.82 \$/MMBtu		
Reagent (Cost _{reag})	1.62 \$/gallon for a 50 percent solution of ammonia*		
Water (Cost _{water})	0.0088 \$/gallon*		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Ash Disposal (for coal-fired boilers only) (Cost _{ash})	\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, 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) =	0.015
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	\$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost (\$/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	0.037 - Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3
Fuel Cost (\$/MMBtu)	5.14	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the 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/ .	3.822 based 2016 fuel cost data for Gadsby from data reported to the U.S. Energy Information Administration (EIA) on EIA Form EIA-923, Available at http://www.eia.gov/electricity/data/eia923/ .
Ash Disposal Cost (\$/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)

SNCR Design Parameters

The following design parameters for the SNCR 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) =	$B_{mw} \times NPHR =$	825	MMBtu/hour
Maximum Annual MW Output (B_{mw}) =	$B_{mw} \times 8760 =$	700,800	MW/year
Estimated Actual Annual MW Output (Boutput) =		175,200	MW/year
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.03	
Total System Capacity Factor (CF_{total}) =	$(Boutput/B_{mw}) \times (tsnrcr/365) =$	0.25	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	2190	hours
NOx Removal Efficiency (EF) =	$(NO_{xin} - NO_{xout})/NO_{xin} =$	17.00	percent
NOx removed per hour =	$NO_{xin} \times EF \times Q_b =$	16.83	lb/hour
Total NO _x removed per year =	$(NO_{xin} \times EF \times Q_b \times t_{op})/2000 =$	18.43	tons/year
Coal Factor ($Coal_f$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1E6 / HHV =$		
Elevation Factor (ELEVf) =	$14.7 \text{ psia}/P =$	1.17	
Atmospheric pressure at 4240 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7) / 518.6]^{5.256} \times (1/144) \times$ =	12.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.15	

Not applicable; factor applies only to coal-fired boilers

Not applicable; factor applies only to coal-fired boilers

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

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x\text{in}} \times Q_{\text{G}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NO}_x} \times \text{SR}) =$ (where SR = 1 for NH ₃ ; 2 for Urea)	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	77	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	8	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	2,724	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times \text{NO}_{x\text{in}} \times \text{NSR} \times Q_{\text{G}}) / \text{NPHR} =$	4.74	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.03	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1\text{E}6) / \text{HHV} =$	0.00	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,186,522 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,375,439 in 2016 dollars
Total Capital Investment (TCI) =	\$3,330,548 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,186,522 in 2016 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	\$1,375,439 in 2016 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =		\$79,398 in 2016 dollars
Indirect Annual Costs (IDAC) =		\$475,694 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC		\$555,092 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	0.015 x TCI =	\$49,958 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$28,766 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$384 in 2016 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2016 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$290 in 2016 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2016 dollars
Direct Annual Cost =		\$79,398 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$1,499 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$474,195 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$475,694 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =		\$555,092 per year in 2016 dollars
NOx Removed =		18.43 tons/year
Cost Effectiveness =		\$30,121 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N₂ and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 5.13). The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates ($\pm 30\%$) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the **Data Inputs** tab and click on the **Reset Form** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the **SCR Design Parameters** tab to see the calculated design parameters and the **Cost Estimate** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility ▼

What type of fuel does the unit burn? Natural Gas ▼

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.25 * NOTE: You must document why a retrofit factor of 1.25 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 105 MW

What is the higher heating value (HHV) of the fuel? 1,050 Btu/scf

What is the estimated actual annual MW output? 229,950 MW/year

Enter the net plant heat input rate (NPHR) 11.00 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 4240 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable ▼

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

Not applicable to units burning 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.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.31	8,730
Lignite	0	0.91	6,534

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

For coal-fired boilers, 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 boiler operates (t_{plant})	365 days
Inlet NO _x Emissions (NO _{xin}) to SCR	0.1 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	80 percent
Stoichiometric Ratio Factor (SRF)	1.050

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

Estimated operating life of the catalyst ($t_{catalyst}$)	24,000 hours
Estimated SCR equipment life	10 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored})	29 percent*
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

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

Select the reagent used

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Gas temperature at the SCR inlet (T)	258 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	340.5 ft ³ /min-MMBtu/hour

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Reagent (Cost _{reag})	3.56 \$/gallon for a 29 percent solution of ammonia		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Catalyst cost (CC _{replace})	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)*		
Operator Labor Rate	60.00 \$/hour (including benefits)*		
Operator Hours/Day	4.00 hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* \$3.56/gallon is a default value for the reagent cost. User should enter actual value, if known.

* \$160/cf is a default value for the catalyst cost. User should enter actual value, if known.

* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 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)	3.56	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the 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/ .	
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)
Catalyst Cost (\$/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

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) =	$Bmw \times NPHR =$	1,155	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	919,800	MW/year
Estimated Actual Annual MW Output (Boutput) =		229,950	MW/year
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10	
Total System Capacity Factor (CF_{total}) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.25	fraction
Total operating time for the SCR (t_{op}) =	$CF_{total} \times 8760 =$	2190	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	80.0	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_b =$	92.40	lb/hour
Total NO _x removed per year =	$(NOx_{in} \times EF \times Q_b \times t_{op})/2000 =$	101.18	tons/year
NOx removal factor (NRF) =	$EF/80 =$	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_b \times (460 + T)/(460 + 700)_{n_{scr}} =$	243,439	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	9.72	/hour
Residence Time	$1/V_{space} =$	0.10	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 =	$(\%S/100) \times (64/32) \times 1E6/HHV =$		
Elevation Factor (ELEVF) =	$14.7\ psia/P =$	1.17	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{6.256} \times (1/144)^* =$	12.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.25	

Not applicable; factor applies only to coal-fired boilers

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightssystemsgrc.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 = $H_{catalyst}/(t_{scr} \times 24\ hours)$ rounded to the nearest integer	0.311	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_b \times EF_{adj} \times Slipadj \times Noxadj \times Sadj \times (Tadj/Nscr) =$	25,039.88	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}/(16\ ft/sec \times 60\ sec/min) =$	254	ft ²
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1 =$	34	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst} =$	292	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5} =$	17.1	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7\ ft + h_{layer}) + 9\ ft =$	173	feet

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x\text{in}} \times Q_{\text{B}} \times \text{EF} \times \text{SFR} \times \text{MW}_{\text{R}}) / \text{MW}_{\text{NO}_x} =$	36	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / \text{Csol} =$	124	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	17	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24) / \text{Reagent Density} =$	5,558	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	612.60	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

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

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

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

$$TCI = 60,670 \times B_{MW} \times ELEV \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,270 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 9,760 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,275 \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,082 \times Q_B \times ELEV \times RF$$

Total Capital Investment (TCI) =

\$14,470,496

in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$666,351 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$2,063,769 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,730,120 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	0.005 x TCI =	\$72,352 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$128,962 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$49,639 in 2016 dollars
Annual Catalyst Replacement Cost =		\$415,397 in 2016 dollars
	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}} / R_{\text{layer}}) \times \text{FWF}$	
Direct Annual Cost =		\$666,351 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$3,496 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$2,060,273 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$2,063,769 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$2,730,120 per year in 2016 dollars
NOx Removed =	101.18 tons/year
Cost Effectiveness =	\$26,983 per ton of NOx removed in 2016 dollars

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(May 2016)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated in 2016). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For the more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the *SNCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

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

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. * NOTE: You must document why a retrofit factor of 1.25 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?

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

What is the estimated actual annual MW output?

Is the boiler a fluid-bed boiler?

Enter the net plant heat input rate (NPHR)

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight
or
Select the appropriate SO₂ emission rate:

Ash content (%Ash): 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, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	2.35	10.4	11,814	2.79
Sub-Bituminous	0	0.31	5.8	8,730	2.04
Lignite	0	0.91	14.3	6,534	1.85

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

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	4240 Feet above sea level
Inlet NO _x Emissions (NO _{x,in}) to SNCR	0.1 lb/MMBtu		
NO _x Removal Efficiency (EF) provided by vendor (Enter "UNK" if value is not known)	10 percent		
Estimated Normalized Stoichiometric Ratio (NSR)	1.05		*The NSR value of 1.05 is a default value. User should enter actual value, if known.
Concentration of reagent as stored (C_{stored})	50 percent*		*The reagent concentration of 50% is a default value. User should enter actual value, if known.
Density of reagent as stored (ρ_{stored})	71 lb/ft ³		
Concentration of reagent injected (C_{inj})	50 percent		
Number of days reagent is stored ($t_{storage}$)	14 days		
Estimated equipment life	10 Years		
Select the reagent used	Ammonia		

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³
19% aqueous NH ₃	58 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year	2016		
CEPCI for 2016	550.9	584.6	2012 CEPCI
Annual Interest Rate (i)	7 Percent		
Fuel (Cost _{fuel})	3.82 \$/MMBtu		
Reagent (Cost _{reag})	1.62 \$/gallon for a 50 percent solution of ammonia*		
Water (Cost _{water})	0.0088 \$/gallon*		
Electricity (Cost _{elect})	0.0370 \$/kWh		
Ash Disposal (for coal-fired boilers only) (Cost _{ash})	\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, 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) =	0.015
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	\$1.62/gallon of 50% urea solution	Based on vendor quotes collected in 2014.	
Water Cost (\$/gallon)	0.0088	Average combined water/wastewater rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .	
Electricity Cost (\$/kWh)	0.039	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .	0.037 - Average annual electricity cost for utilities is based on 2015 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3 .
Fuel Cost (\$/MMBtu)	5.14	Weighted average cost based on average 2014 fuel cost data for power plants compiled by the 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/ .	3.822 based 2016 fuel cost data for Gadsby from data reported to the U.S. Energy Information Administration (EIA) on EIA Form EIA-923, Available at http://www.eia.gov/electricity/data/eia923/ .
Ash Disposal Cost (\$/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 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/ .	1,050 Btu/scf was obtained from PacifiCorp 2015 Emission Inventory data and confirmed with daily heating value from Questar (accessed 4/7/2017)

SNCR Design Parameters

The following design parameters for the SNCR 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) =	$B_{mw} \times NPHR =$	1,155	MMBtu/hour
Maximum Annual MW Output (B_{mw}) =	$B_{mw} \times 8760 =$	919,800	MW/year
Estimated Actual Annual MW Output (Boutput) =		229,950	MW/year
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10	
Total System Capacity Factor (CF_{total}) =	$(Boutput/B_{mw}) \times (tsnrcr/365) =$	0.25	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	2190	hours
NOx Removal Efficiency (EF) =	$(NO_{xin} - NO_{xout})/NO_{xin} =$	10.00	percent
NOx removed per hour =	$NO_{xin} \times EF \times Q_b =$	11.55	lb/hour
Total NO _x removed per year =	$(NO_{xin} \times EF \times Q_b \times t_{op})/2000 =$	12.65	tons/year
Coal Factor ($Coal_f$) =	1 for bituminuous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1E6 / HHV =$		
Elevation Factor (ELEVf) =	$14.7 \text{ psia}/P =$	1.17	
Atmospheric pressure at 4240 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7) / 518.6]^{5.256} \times (1/144)^*$ =	12.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.25	

Not applicable; factor applies only to coal-fired boilers

Not applicable; factor applies only to coal-fired boilers

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

Reagent Data:

Type of reagent used

Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x_{in}} \times Q_G \times NSR \times MW_R) / (MW_{NO_x} \times SR) =$ (where SR = 1 for NH ₃ ; 2 for Urea)	45	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	90	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density} =$	9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	3,178	gallons (storage needed to store a 14 day reagent supply)

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	0.1424

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NO_{x_{in}} \times NSR \times Q_G) / NPHR =$	5.18	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol} / \text{Density of water}) \times ((C_{stored} / C_{inj}) - 1) =$	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent ($\Delta Fuel$) =	$H_v \times m_{reagent} \times ((1/C_{inj}) - 1) =$	0.04	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1E6) / HHV =$	0.00	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,485,462 in 2016 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2016 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,563,169 in 2016 dollars
Total Capital Investment (TCI) =	\$3,963,221 in 2016 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_b \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_b/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,485,462 in 2016 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_b \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2016 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_b)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_b/NPHR)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

Balance of Plan Costs (BOP_{cost}) =	\$1,563,169 in 2016 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$93,767 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$566,057 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$659,823 in 2016 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$59,448 in 2016 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$33,560 in 2016 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$420 in 2016 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$0 in 2016 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$338 in 2016 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2016 dollars
Direct Annual Cost =		\$93,767 in 2016 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,783 in 2016 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$564,273 in 2016 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$566,057 in 2016 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$659,823 per year in 2016 dollars
NOx Removed =	12.65 tons/year
Cost Effectiveness =	\$52,171 per ton of NOx removed in 2016 dollars