NO_X RACT ANALYSIS

Architect of the Capitol / U.S. Capitol Power Plant

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February 2022

Project 222101.0008

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1. INTRODUCTION

The U.S. Capitol Power Plant (CPP) provides heating and cooling to 23 buildings in the Capitol Complex including the House and Senate office buildings, the U.S. Supreme Court, the U.S. Capitol Building, and the Library of Congress. Additionally, the CPP provides heating and cooling to the U.S. Government Printing Office, Union Station, and the Postal Square Building. Several of the CPP's emission units are subject to the District of Columbia's Reasonably Available Control Technology (RACT) regulations for nitrogen oxides (NO_X). CPP is submitting this alternative RACT plan to detail RACT compliance for applicable emission units.

1.1 Facility Description

The CPP's operations include seven (7) boilers that provide heating to Capitol Hill. Boiler 1 and Boiler 2 (CU-1 and CU-2) are each rated at 160 million British thermal units per hour (MMBtu/hr) on coal and 60 MMBtu/hr on natural gas. Boiler 3 (CU-3) is rated at 203 MMBtu/hr. The four remaining boilers (CU-4 through CU-7) are each rated 60 MMBtu/hr. Boilers 1 and 2 vent to the East Stack, while Boilers 3 through 7 vent to the West Stack. Boilers 3 through 7 are equipped with low NO_X burner technology. CPP also has Chapter 2 permits allowing a temporary boiler rated at up to 99 MMBtu/hr to be brought onsite for up to 180 days at a time and operation of a Cogeneration Plant consisting of a 7.5-megawatt (MW) combustion turbine equipped with a 71.9 MMBtu/hr heat recovery steam generator (HRSG). Table 1-1 provides details of the boilers and cogeneration equipment at the CPP.

Table 1-1. Boiler and Combustion Turbine Specifications

Source	Installation Year	Capacity	Fuel
Boiler 1 (CU-1)	1952	160 MMBtu/hr 60 MMBtu/hr	Coal Natural Gas
Boiler 2 (CU-2)	1952	160 MMBtu/hr 60 MMBtu/hr	Coal Natural Gas
Boiler 3 (CU-3)	1952	203 MMBtu/hr 203 MMBtu/hr	Natural Gas Fuel Oil
Boiler 4 (CU-4)	1963	60 MMBtu/hr 60 MMBtu/hr	Natural Gas Fuel Oil
Boiler 5 (CU-5)	1963	60 MMBtu/hr 60 MMBtu/hr	Natural Gas Fuel Oil
Boiler 6 (CU-6)	1963	60 MMBtu/hr 60 MMBtu/hr	Natural Gas Fuel Oil
Boiler 7 (CU-7)	1963	60 MMBtu/hr 60 MMBtu/hr	Natural Gas Fuel Oil
Combustion Turbine and HRSG (CT-1 and HRSG-1)	2015	7.5 MW CT 71.9 MMBtu/hr HRSG	Natural Gas Fuel Oil
Temporary Boiler	Brought onsite as needed up to 180 days at a time	Up to 99 MMBtu/hr	Natural Gas Fuel Oil

Other NO_X emission sources at the CPP include the following:

- One (1) emergency generator
- One (1) emergency fire pump; and
- Twelve (12) coal car burners, 1.25 MMBtu/hr each.

1.2 Regulatory Review

On November 26, 2021, the Department of Energy and Environment (DOEE) finalized amendments to the District of Columbia Municipal Regulation (DCMR) Title 20 Chapter 8, Air Quality – Asbestos, Sulfur, Nitrogen Oxides, and Lead (20 DCMR 8) for facilities required to meet RACT standards for NO_X. Presumptive NO_X limits as established in the recently finalized regulation under 20 DCMR 805.5(e) and 20 DCMR 805.4 for equipment types operated by the CPP are summarized in Table 1-2.

Table 1-2. Presumptive NO_x RACT Emission Limits

Emission Unit Type	CPP Emission Unit(s)	Emission Unit Size	Presumptive RACT Emission Limit
Combustion Turbines Burning Liquid Fuels	CT-1 and HRSG-1	>50 MMBtu/hr	42 parts per million by volume, dry (ppmvd)
Dry Bottom Coal-Fired Units	CU-1 and CU-2	≥100 MMBtu/hr	0.12 lb/MMBtu
Non-Coal Fired Units	CU-3	≥100 MMBtu/hr	0.12 lb/MMBtu when burning oil or a combination of fuel oil and natural gas 0.05 lb/MMBtu when burning natural gas only
	CU-4 to CU-7 and Temporary Boiler	≥25 and <100 MMBtu/hr	0.09 lb/MMBtu when burning oil[1] 0.05 lb/MMBtu when burning natural gas only

If an existing unit is unable to meet these new limits, the facility must submit by no later than March 1, 2022 an alternative RACT plan demonstrating that the new limits are not technically or economically feasible. Per 20 DCMR 805.2(c), the components of the alternative RACT application include:

> *1. Demonstration that it is not technically or economically feasible for the emission unit to comply with the new emission limitation.*

[1] NO_X emission limit for oil burning is for units that have not taken limits to restrict oil usage to periods of gas curtailment, testing and maintenance. Recognizing our mission and the criticality for mainaining the continuity of government, the CPP has not taken limits to restrict oil usage on any boilers.

2. Provide a study of the capabiltiy of the emission unit to apply the following NO_X control options and their expected effectiveness:

a. Low NO_X Burners (LNB);
b. Overfire Air (OFA);
c. Flue gas Recirculation (FGR);
d. Burners Out Of Services (BOOS);
e. Selective Non-Catalytic Reduction (SNCR); and,
f. Selective Catalytic Reduction (SCR).

3. Determine an emissions limitation reflecting the application of RACT.

CPP is submitting this alternative RACT plan to meet the requirements of 20 DCMR 805.2(b).

1.3 RACT Requirements

The following sections outline the alternative RACT plan for the applicable sources at the CPP.

1.3.1 Exempt Units

Emergency standby engines are not subject to NO_X RACT emission limits per 20 DCMR 805.1(c)(5). Therefore, the emergency generator and emergency fire pump are exempt from RACT requirements. The coal car burners are exempt per 20 DCMR 805.1(c)(2). As such, these units are not discussed further in this alternative RACT plan.

1.3.2 Presumptive RACT

Sources can choose to comply with presumptive RACT limits set forth in 20 DCMR 805.5(e) and 20 DCMR 805.4, which are summarized in Table 1-2. CPP will comply with the presumptive RACT limits for the following sources:

- Boilers 1 and 2 (CU-1 and CU-2);
- Combustion Turbine and HRSG (CT-1 and HRSG-1); and
- Temporary Boiler.

The presumptive RACT limits will become effective on January 1, 2023.

1.3.3 Case-by-Case RACT Determination

For sources that are unable to meet presumptive RACT limits, facilities must propose an alternative RACT emission limitation (i.e., a "case-by-case RACT limit") and apply for a case-by-case RACT from the DOEE. CPP proposes to comply with alternative RACT emission limits for Boilers 3 through 7 (CU-3 through CU-7).

Section 2 of this application includes the demonstration of the technical and economic feasibiltiy of the NO_X control options and the recommended RACT emissions limitations for affected units at the CPP.

2. RACT ANALYSIS

As discussed above, several sources at CPP are subject to a case-by-case RACT determination. This section provides details on the methodology used to determine the proposed RACT.

2.1 Top-Down Methodology

Case-by-case RACT determinations are traditionally based on a top-down methodology. Presented below are the five (5) basic steps of the top-down RACT review.

2.1.1 Step 1: Identify All Control Technologies

Under Step 1, all available control technologies are identified for each emission unit in question. Per 20 DCMR 805.2, the following NO_X control options must be evaluated:

- LNB;
- OFA;
- FGR;
- BOOS;
- SNCR; and
- SCR.

2.1.2 Step 2: Eliminate Technically Infeasible Options

After control technologies are identified under Step 1, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology.

2.1.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

In Step 3, remaining control technology options are ranked based on their control effectiveness, from highest to lowest control efficiency. This list must identify, at a minimum, the baseline emissions of NO_X before implementation of each control option, the estimated reduction potential or control efficiency of each control option, and the estimated emissions after the application of each control option and the economic impacts.

2.1.4 Step 4: Evaluate Most Effective Controls and Document Results

Beginning with the highest-ranked control technology option from Step 3, detailed economic, energy, and environmental impact evaluations are performed in Step 4. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

2.1.4.1 Cost Analysis Methodology: Capital Costs

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. Environmental Protection Agency's (EPA's) Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (CCM) and other industry resources. Based on the CCM, capital costs are annualized over a 20-year lifespan of the control equipment. Note that this is conservative for CPP's alternate RACT analysis as the boilers are likely to be replaced during this timeframe. According to the CPP's latest Master Utility Plan, these boilers are anticipated to be replaced in five to ten years which would further increase annualized costs as any control technology will only be used for the remainder of each boiler's operating life.

2.1.4.2 Cost Analysis Methodology: Emissions

Annualized costs are then converted to a dollar per ton of pollutant removed cost efficiency value to determine whether a control technology is economically feasible. For this alternative RACT analysis, CPP has utilized annual average actual emissions from 2020 and 2021 for each boiler. The CPP, as part of its long-term strategic plan, took an important initial step in modernizing fuel combustion operations with the Cogeneration project. This project resulted in CPP voluntarily proposing and accepting an aggressive lower potential sitewide NO_X limit of 196.7 tons per year (tpy) via a sitewide NOx PAL permit.[2] The permit action reduced sitewide potential emissions from CPP by approximately 81%.

It should also be noted that the base steam load of the AOC campus is served by the Cogeneration System which meets the presumptive RACT limits. Boilers 3 through 7, which are equipped with low NO_X burners, are used to meet steam demands above the Cogeneration Plant capacity and to provide redundancy if Cogeneration Plant operation is interrupted. Frequently, the five (5) boilers are operating in low-fire while the combustion turbine is operating. The annual load factor of each boiler is less than 15%. Additionally, the five (5) boilers have been in operation for 60 years. By part loading multiple boilers, the furnace exit temperatures are reduced which contributes to the extended longevity of the units and reduces NO_X formation.

Our actual emissions today are roughly 4.4% of the pre-Cogeneration potential emissions. CPP will continue to comply with the PAL permit actual emissions limits which provide a more restrictive emission level than the potential emissions from each boiler individually. Consistent with our compliance demonstration with our actual PAL, we have provided economic analyses based on the actual emissions from our units for which we are proposing an alternative RACT.

2.1.4.3 Evaluating Economic Feasibility

Cost efficiency values, in dollars per ton of NO_X removed, are then reviewed to determine if each control technology is cost effective. DOEE has not established a threshold for cost efficiency for RACT. CPP has utilized RACT cost effectiveness thresholds for other states to determine whether each technology is cost effective. Based on a recent review by Pennsylvania, cost effectiveness for RACT ranges from $2,500 to $5,500 per ton of NO_X removed.[3] If the control technology with the highest control efficiency is not cost effective, it is eliminated and the next highest ranked technology from step 3 is evaluated for cost until a cost effective technology is found or all technologies are eliminated.

2.1.5 Step 5: Select RACT

Using the result of the prior steps to determine the appropriate control technology, the final step is to determine the emission limit that represents the RACT limit.

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[2] Permit No. 6577 issued by DOEE with an effective date of June 6, 2013. The CPP also operates under a PAL of 248.1 tpy of NO_X in Permit No. EPA-R3-PAL-001 issued by the U.S. EPA with an effective date of January 23, 2013.

[3] 87 FR 3437, January 24, 2022.

2.2 NO_X RACT Assessment for Boiler 3 (CU-3)

Boiler 3 is a 203 MMBtu/hr Wickes boiler that is permitted to operate on either fuel oil or natural gas. Boiler 3 has been in service for over 70 years and is a converted stoker fired coal boiler. Because of the furnace geometry, four burners in a single row were installed to obtain the unit steam output. All four burners utilize low NO_X burner technology. The boiler design includes a flue gas feedwater economizer. Emissions from Boiler 3 are combined with emissions from Boilers 4 through 7 before venting to the atmosphere from the West Stack.

There are three (3) types of chemical kinetic processes that form NO_X emissions from boilers referred to as: 1) thermal NO_X, 2) fuel NO_X, and 3) prompt NO_X. Thermal NO_X is generated by the oxidation of molecular nitrogen (N_2) in the combustion air as it passes through the flame in the boiler. This reaction requires high temperatures, hence the name thermal NO_X. The formation of nitrogen oxide (NO) from oxygen (O_2) and N_2 in air at high temperatures is described by the well-known Zeldovich mechanism. Fuel NO_X is the result of the conversion of nitrogen compounds contained in fuels to NO_X during fuel combustion. Prompt NO_X is formed by a combination of reactions between nitrogen, oxygen, and hydrocarbon radicals and is mostly significant in low-temperature, fuel-rich conditions where residence times are short.

2.2.1 Step 1: Identify All Control Technologies for NO_X

Step 1 in a top-down analysis is to identify all available control technologies. The evaluation of potential controls for NO_X emissions includes both an investigation of end-of-pipe (post-combustion methods) which control all forms of NO_X and combustion modifications/optimization that reduce the formation of thermal NO_X. Table 2-1 contains a list of the various technologies that have been evaluated for the control of NO_X from Boiler 3 per 20 DCMR 805.2(c)(2) and each is further discussed below.

Table 2-1. Potentially Available NO_X Control Technologies for Boiler 3

Potentially Applicable NO_X Control Technologies
SNCR
SCR
OFA
BOOS
LNB
FGR

2.2.1.1 SNCR

SNCR is a post-combustion emissions control technology which involves injection of an ammonia-type reagent (typically ammonia or urea) into the furnace. The ammonia (NH_3) or a urea solution is injected into the gas stream to chemically reduce NO_X to form N_2 and water. High temperatures, optimally between 1,600 to 2,000 degrees Fahrenheit (°F) for ammonia injection and 1,650 to 2,100 °F for urea injection, promote the reaction via the following equation: [4]

[4] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NO_X Control, April 2019, Pages 1-9 to 1-11.

$$NH_3 + NO + {}^{1}/_{4}\,O_2 \rightarrow N_2 + {}^{3}/_{4}\,H_2O$$

2.2.1.2 SCR

SCR is an exhaust gas treatment process in which NH_3 is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3, NO, and NO_2 react to form water and N_2 in the same reaction as for SNCR technology. The presence of the catalyst promotes this reaction at a much lower temperature than that required for SNCR, typically between 480 and 800 °F.[5]

2.2.1.3 OFA

OFA is a type of staged combustion control, wherein the amount of combustion air introduced into the burner zone is limited. Additional combustion air is introduced after the burner zone through OFA ports. By spreading out the combustion, oxygen concentrations are limited in the lower portions of the boiler, thereby limiting the oxidation of fuel-bound nitrogen and the formation of fuel NO_X.

2.2.1.4 BOOS

BOOS is a staged combustion technique which involves introducing additional natural gas at lower zones (fuel-rich zone) and additional air through registers of non-operating burners at higher zones to complete combustion. Note that by taking burners out of service the overall capacity of the emission unit is reduced.

2.2.1.5 LNBs

The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation at the flame. LNBs are designed to control fuel and air mixing to create larger and more branched flames. Peak flame temperatures are reduced, resulting in less NO_X formation.

2.2.1.6 FGR

With this technology, cooled flue gas is recirculated back in with the combustion air and thus reduces the combustion temperature by lowering the oxygen content of the mix and absorbing heat from the flame. The lower temperature lowers the amount of thermal NO_X that is created.

2.2.2 Step 2: Eliminate Technically Infeasible Options for NO_X Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The remaining technologies are then carried into Step 3.

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[5] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Control, June 2019, Section 2.2.2.

2.2.2.1 SNCR

SNCR requires a high but very specific temperature range (generally between 1,600 and 2,100 °F) and residence time at this temperature to be effective. Boiler 3 operates with an exhaust temperature below 300 °F.

Due to the low exhaust temperature, SNCR is a technically infeasible control technology and therefore is not RACT. Further evaluation of the technology is not required. However, in anticipation of questions from DOEE, CPP has provided a cost effectiveness evaluation in Appendix D to demonstrate that SNCR is both technically and economically infeasible for Boiler 3.

2.2.2.2 SCR

The SCR process is temperature sensitive. Any exhaust gas temperature fluctuation reduces removal efficiency and upsets the NH_3/NO_X molar ratio. SCR also requires an optimum temperature range of 480 to 800 °F and fairly constant temperatures, or NO_X removal efficiency will decrease.[6] As stated above, Boiler 3 operates with an exhaust temperature below 300 °F.

Therefore, SCR would be ineffective at controlling NO_X emissions and is not RACT. Further evaluation of the technology is not required. However, in anticipation of questions from DOEE, CPP has provided a cost effectiveness evaluation in Appendix D to demonstrate that SCR is both technically and economically infeasible for Boiler 3.

2.2.2.3 OFA

Installing an overfire air system for NO_X removal is not technically feasible for Boiler 3. Due to the capacity of the boiler, the fuels utilized, and the existing low NO_X burners, no additional NO_X reduction is expected with this technology. Additionally, the physical configuration and age of the boiler make installation of OFA technically infeasible, and further evaluation of the technology is not required.

2.2.2.4 BOOS

Boiler 3 is a multiple burner unit with four (4) burners. As such, BOOS is evaluated for feasibility. Based on recent combustion analysis data for Boiler 3, there is no improvement in NO_X formation whether the burners are operating at low or high loading. Boiler 3 currently operates near 50% of boiler design capacity, with all four (4) burners operating at roughly 50% capacity. BOOS at 50% design capacity could potentially have two (2) burners at 100% capacity, but BOOS applied to CPP would require three (3) burners at 66% capacity to meet the reliable steam output criteria of the plant [e.g., even with the loss of one (1) of the three (3) burners, the remaining two (2) burners could satisfy the output]. Additionally, the four (4) burners are in a flat configuration which is not beneficial for BOOS. The implementation of BOOS on Boiler 3 is not considered an applicable RACT NO_X improvement method due to the demonstrated lack of NO_X reduction that would result from the staging of linear configured burners as well as the fact that the existing burners are low NO_X burners. A summary of the most recent combustion analysis data is provided in Appendix B, along with a chart of NO_X, CO, and excess air changes with changes in boiler output.

[6] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOX Control, June 2019, Section 2.2.2.

For these reasons, BOOS is not considered to be technically feasible for controlling NO_X emissions and is not RACT. Further evaluation of the technology is not required.

2.2.2.5 LNBs

Boiler 3 is equipped with LNB technology. However, technology has improved and the burners could be replaced with newer burners that would emit NO_X at a lower rate. The installation of newer LNBs is a technically feasible option for lowering NO_X emissions from Boiler 3 and is therefore considered further in this analysis.

2.2.2.6 FGR

FGR is a technically feasible option for lowering NO_X emissions from Boiler 3. Since FGR would require replacement of the burners, more advanced LNB technology would be installed at the same time. The existing low NO_X burners cannot be utilized with FGR. Replacing the burners with newer LNBs equipped with FGR is considered technically feasible and is therefore considered further in this analysis.

2.2.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 in the top-down RACT analysis procedure is to rank remaining control technologies by control effectiveness. Table 2-2 compares the relative effectiveness of the technically feasible control technologies.

Table 2-2. Ranking of Remaining Control Technologies for Boiler 3

Pollutant	Control Technology	Estimated NO_X Emission Factor[7]
NO_X	LNB + FGR	0.03 lb/MMBtu
	LNB	0.05 lb/MMBtu

2.2.4 Step 4: Evaluate Most Effective Controls and Document Results

In Step 4, the remaining control technologies, in order from most stringent control to least, are evaluated on the basis of economic, energy, and environmental considerations.

2.2.4.1 LNBs with FGR

Replacing all existing LNBs with new LNBs with FGR has the highest control efficiency of the remaining control options.

Based on a controlled emission rate of 0.03 lb/MMBtu, the cost effectiveness for Boiler 3 is estimated to be $25,719 per ton of NO_X removed. Accordingly, installation of LNBs with FGR on Boiler 3 is not considered an economically feasible option.

Capital costs for this analysis were based on a site-specific engineering analysis and information from potential vendors (refer to Appendix E). The methodology and assumptions used to determine this cost effectiveness are presented in Appendix A.

[7] Provided by Affiliated Engineers, Inc. (AEI) for the specific equipment in the cost quotes provided in Appendix E.

2.2.4.2 LNBs

LNBs without FGR technology is the next most efficient NO_X control technology. Based on a controlled emission rate of 0.05 lb/MMBtu, the cost effectiveness for Boiler 3 is estimated to be $27,219 per ton of NO_X removed. Accordingly, installation of modern LNBs on Boiler 3 is not considered an economically feasible option.

Capital costs for this analysis were based on a site-specific engineering analysis and information from potential vendors (refer to Appendix E). The methodology and assumptions used to determine this cost effectiveness are presented in Appendix A.

2.2.5 Step 5: Select RACT

As RACT, CPP will continue to utilize the existing low NO_X burners and to employ good combustion practices, proper boiler operation, and minimization of excess air. Due to the combined stack configuration, CPP is proposing a single RACT limit for the West Stack of 0.2 lb/MMBtu. Refer to Section 2.4 for details of this proposed RACT emission limit.

2.3 NO_X RACT Assessment for Boilers 4-7 (CU 4-7)

Boilers 4 through 7 are each 60 MMBtu/hr packaged watertube boilers that are permitted to operate on either fuel oil or natural gas. Each boiler is equipped with a single low NO_X burner. Each has been in service for almost 60 years. Emissions from Boilers 4 through 7 are combined with emissions from Boiler 3 before venting to atmosphere from the West Stack. Mechanisms for NO_X production in Boilers 4 to 7 mirror those in Boiler 3, refer to Section 2.2 for a detailed description.

2.3.1 Step 1: Identify All Control Technologies for NO_X

Step 1 in a top-down analysis is to identify all available control technologies. The evaluation of potential controls for NO_X emissions includes both an investigation of end-of-pipe (post-combustion methods) and combustion modifications/optimization that reduce the formation of thermal NO_X. Table 2-3 contains a list of the various technologies that have been evaluated for the control of NO_X from Boilers 4 through 7 per 20 DCMR 805.2(c)(2). Refer to Section 2.1.1 for descriptions of each control technology.

Table 2-3. Potentially Available NO_X Control Technologies for Boilers 4-7

Potentially Applicable NO_X Control Technologies
SNCR
SCR
OFA
BOOS
LNB
FGR

2.3.2 Step 2: Eliminate Technically Infeasible Options for NO_X Control

Step 2 in a RACT top-down analysis is to eliminate the control options identified in Step 1 which are technically infeasible. The remaining technologies are then carried into Step 3.

2.3.2.1 SNCR

SNCR requires a high but very specific temperature range (generally between 1,600 and 2,100 °F) and residence time at this temperature to be effective. Boilers 4 through 7 typically operate with exhaust temperatures of 300 to 600 °F based on available stack testing data.

Due to the low exhaust temperature, SNCR is considered a technically infeasible control technology and therefore is not RACT. Therefore, further evaluation of the technology is not required. However, in anticipation of questions from DOEE, CPP has provided a cost effectiveness evaluation in Appendix D to demonstrate that SNCR is both technically and economically infeasible for Boilers 4 through 7.

2.3.2.2 SCR

The SCR process is temperature sensitive. Any exhaust gas temperature fluctuation reduces removal efficiency and upsets the NH_3/NO_X molar ratio. SCR also requires an optimum temperature range of 480 to 800 °F and fairly constant temperatures, or NO_X removal efficiency will decrease.[8] As stated above, Boilers 4 through 7 typically operate with exhaust temperatures of 300 to 600 °F based on available stack testing data. Given this wide range of temperatures which are mostly below the optimum operating range of SCR, SCR is considered technically infeasible for Boilers 4 through 7 and is not RACT. Therefore, further evaluation of the technology is not required. However, in anticipation of questions from DOEE, CPP has provided a cost effectiveness evaluation in Appendix D to demonstrate that SCR is both technically and economically infeasible for Boilers 4 through 7.

2.3.2.3 OFA

Installing an overfire air system for NO_X removal is not technically feasible for Boilers 4 through 7. Due to the capacity of the boilers, the fuels utilized, and the existing low NO_X burners, no additional NO_X reduction is expected with this technology. Additionally, the physical configuration and age of the boilers make installation of OFA technically infeasible, and further evaluation of the technology is not required.

2.3.2.4 BOOS

Boilers 4 through 7 are each configured with a single burner, meaning it is impossible to operate these boilers by taking a burner out of service. Therefore, BOOS is not technically feasible for controlling NO_X emissions and is not RACT. Further evaluation of the technology is not required.

2.3.2.5 LNBs

Boilers 4 through 7 are equipped with LNB technology. However, technology has improved, and the burners could be replaced with newer burners that would emit NO_X at a lower rate. The installation of newer LNBs is a technically feasible option for lower NO_X emissions from Boilers 4 through 7 and is therefore considered further in this analysis.

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[8] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Control, EPA/452/B-02-001, Page 2-9.

2.3.2.6 FGR

FGR is a technically feasible option for lowering NO_X emissions from Boilers 4 through 7. Since FGR would require replacement of the burners, more advanced LNB technology would be installed at the same time. The existing low NO_X burners cannot be utilized with FGR. Replacing the burners with newer LNBs equipped with FGR is considered technically feasible and is therefore considered further in this analysis.

2.3.3 Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 in the top-down RACT analysis procedure is to rank remaining control technologies by control effectiveness. Table 2-4 compares the relative effectiveness of the technically feasible control technologies.

Table 2-4. Ranking of Remaining Control Technologies for Boilers 4-7

Pollutant	Control Technology	Estimated NO_X Emission Factor[9]
NO_X	LNB + FGR	0.03 lb/MMBtu
	LNB	0.05 lb/MMBtu

2.3.4 Step 4: Evaluate Most Effective Controls and Document Results

In Step 4, the remaining control technologies, in order from most stringent control to least, are evaluated on the basis of economic, energy, and environmental considerations.

2.3.4.1 Low NO_X Burners with FGR

Replacing the existing LNBs with modern LNB with FGR is the best control option identified.

Based on a controlled emission rate of 0.03 lb/MMBtu, the cost effectiveness of LNB with FGR for Boilers 4 through 7 is estimated to be $15,885 to $30,723 per ton of NO_X removed depending on the boiler. Accordingly, installation of modern LNB with FGR on Boilers 4 through 7 is not considered an economically feasible option.

Capital costs for this analysis were based on a site-specific engineering analysis and information from potential vendors (refer to Appendix E). The methodology and assumptions used to determine this cost effectiveness are presented in Appendix A.

2.3.4.2 LNBs

LNBs without FGR technology is the next most efficient NO_X control technology. Based on a controlled emission rate of 0.05 lb/MMBtu, the cost effectiveness for Boilers 4 through 7 is estimated to be $15,447 to $29,569 per ton of NO_X removed depending on the boiler. Accordingly, installation of low NO_X burners on Boilers 4 through 7 is not considered an economically feasible option.

Capital costs for this analysis were based on a site-specific engineering analysis and information from potential vendors (refer to Appendix E). The methodology and assumptions used to determine this cost effectiveness are presented in Appendix A.

[9] Provided by AEI for the specific equipment in the cost quotes provided in Appendix E.

2.3.5 Step 5: Select RACT

As RACT, CPP will continue to utilize the existing low NO_X burners and to employ good combustion practices, proper boiler operation, and minimization of excess air. Due to the combined stack configuration, CPP is proposing a single RACT limit for the West Stack of 0.2 lb/MMBtu. Refer to Section 2.4 for details of this proposed RACT emission limit.

2.4 Proposed RACT Emission Limit for West Stack

As discussed above, the five (5) boilers that exhaust to the West Stack currently are not capable of meeting the presumptive RACT limit and all possible control technologies are not technically or economically effective. Emissions to the West Stack are monitored using a single Continuous Emissions Monitoring System (CEMS) for NO_X. As such, CPP is proposing a single limit for the West Stack of 0.20 lb/MMBtu based on a daily average. This is the current emission limit for Boiler 3 but lower than the current limit for Boilers 4 through 7 of 0.25 lb/MMBtu.

To support this limit, CPP performed an upper prediction limit (UPL) calculation, consistent with EPA's methodology for setting emission limits for existing sources with monitoring data. CPP utilized West Stack CEMS data for 2019 through 2021 in this analysis to account for various operating scenarios including which boilers are used, operating load, and fuel mix. Based on the UPL analysis, an appropriate limit for the West Stack would be 0.22 lb/MMBtu based on a daily average. As such, the prior emissions data for the West Stack supports the proposed limit and the proposed emission limit is lower than the UPL analysis calculated value. Detailed UPL calculations are provided in Appendix C.

In addition to the proposed RACT limit, CPP will also continue to comply with NO_X PALs for site-wide emissions including the boilers, and with NO_X requirements in New Source Performance Standard (NSPS) Subpart Db for Boiler 3.

APPENDIX A. DETAILED COST CALCULATIONS

This appendix contains detailed cost efficiency calculations for:

- Installing LNB with FGR on Boiler 3
- Replacing existing LNBs with modern LNBs for Boiler 3
- Installing LNB with FGR on Boilers 4 through 7
- Replacing existing LNBs with modern LNBs for Boilers through 7

U.S. Capitol Power Plant
Boiler 3 (CU-3)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB)

Cost Item	Computational Method	Cost	Notes
Purchased Equipment Costs			
Burner		$1,050,000 (A)	Project Cost Estimate Provided by AEI dated January 2022.
Direct Installation Costs			
Burner Installation		$80,000	Project Cost Estimate Provided by AEI dated January 2022.
Front Wall Modifications		$60,000	Project Cost Estimate Provided by AEI dated January 2022.
Gas Piping		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Oil Piping		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Wiring		$40,000	Project Cost Estimate Provided by AEI dated January 2022.
Control/BMS Incorporation		$60,000	Project Cost Estimate Provided by AEI dated January 2022.
Electrical		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Total		$300,000 (B)	
Total Purchased Equipment and Direct	(A + B)	$1,350,000 (C)	
Indirect Installation Costs			
Engineering	0.10 (C)	$135,000	Project Cost Estimate Provided by AEI dated January 2022.
Construction and Field Expenses	0.04 (C)	$54,000	Project Cost Estimate Provided by AEI dated January 2022.
Contractor Fees	0.10 (C)	$135,000	Project Cost Estimate Provided by AEI dated January 2022.
Start-up	0.02 (C)	$27,000	Project Cost Estimate Provided by AEI dated January 2022.
Contingencies	0.03 (C)	$40,500	Project Cost Estimate Provided by AEI dated January 2022.
Total		$391,500 (D)	
AOC Required Indirect Installation Costs			
Contingency	0.20 (C + D)	$348,300	Project Cost Estimate Provided by AEI dated January 2022.
Construction Admin	0.04 (C + D)	$69,660	Project Cost Estimate Provided by AEI dated January 2022.
Government Test and QC	0.025 (C + D)	$43,538	Project Cost Estimate Provided by AEI dated January 2022.
AOC Construction Management	0.20 (C + D)	$348,300	Project Cost Estimate Provided by AEI dated January 2022.
AOC PM Fees	0.05 (C + D)	$87,075	Project Cost Estimate Provided by AEI dated January 2022.
Other	0.05 (C + D)	$87,075	Project Cost Estimate Provided by AEI dated January 2022.
Total		$983,948 (E)	
Total Installed Capital Cost	(C + D + E)	$2,725,448 (F)	
Direct Annual Costs		N/A	
Indirect Annual Costs			
Capital Recovery	CRF (F)	$196,129 (G)	Reference EPA CCM 6th Edition, Section 1, Chapter 2, Equation2.8a. CRF based on 20 years and 3.75% interest rate.
Total Annualized Cost	(G)	$196,129	
Cost Effectiveness			
Baseline NO_X Emissions (tpy)		13.3	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		245,380	Average heat input to boiler during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.05	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		6.1	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		7.2	
Cost ($/ton NO_X removed)		$27,219	

[1] To provide a conservative NO_X removal cost estimate, the emissions guarantee for natural gas firing was used to calculate "controlled" emissions. However, this unit burns both fuel oil and natural gas during normal operations. Emissions during fuel oil firing would be higher than 0.05 lb/MMBtu, resulting in fewer tons of NO_X removed by this emissions control option and a higher $/ton cost.

U.S. Capitol Power Plant
Boiler 3 (CU-3)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB) and Flue Gas Recirculation (FGR)

Cost Item	Computational Method	Cost	Notes
Purchased Equipment Costs			
Burner		$1,100,000	Project Cost Estimate Provided by AEI dated January 2022.
FGR Fan		$150,000	
Total Equipment Costs		$1,250,000 (A)	
Direct Installation Costs			
Burner Installation		$80,000	Project Cost Estimate Provided by AEI dated January 2022.
Front Wall Modifications		$60,000	Project Cost Estimate Provided by AEI dated January 2022.
Gas Piping		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Oil Piping		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Breaching		$100,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Damper		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Wiring		$50,000	Project Cost Estimate Provided by AEI dated January 2022.
Control/BMS Incorporation		$60,000	Project Cost Estimate Provided by AEI dated January 2022.
Electrical		$50,000	Project Cost Estimate Provided by AEI dated January 2022.
Total		$460,000 (B)	
Total Purchased Equipment and Direct	(A + B)	$1,710,000 (C)	
Indirect Installation Costs			
Engineering	0.10 (C)	$171,000	Project Cost Estimate Provided by AEI dated January 2022.
Construction and Field Expenses	0.04 (C)	$68,400	Project Cost Estimate Provided by AEI dated January 2022.
Contractor Fees	0.10 (C)	$171,000	Project Cost Estimate Provided by AEI dated January 2022.
Start-up	0.02 (C)	$34,200	Project Cost Estimate Provided by AEI dated January 2022.
Contingencies	0.03 (C)	$51,300	Project Cost Estimate Provided by AEI dated January 2022.
Total		$495,900 (D)	
AOC Required Indirect Installation Costs			
Contingency	0.20 (C + D)	$441,180	Project Cost Estimate Provided by AEI dated January 2022.
Construction Admin	0.04 (C + D)	$88,236	Project Cost Estimate Provided by AEI dated January 2022.
Government Test and QC	0.025 (C + D)	$55,148	Project Cost Estimate Provided by AEI dated January 2022.
AOC Construction Management	0.20 (C + D)	$441,180	Project Cost Estimate Provided by AEI dated January 2022.
AOC PM Fees	0.05 (C + D)	$110,295	Project Cost Estimate Provided by AEI dated January 2022.
Other	0.05 (C + D)	$110,295	Project Cost Estimate Provided by AEI dated January 2022.
Total		$1,246,334 (E)	
Total Installed Capital Cost	(C + D + E)	$3,452,234 (F)	
Direct Annual Costs		N/A	
Indirect Annual Costs			
Capital Recovery	CRF (F)	$248,430 (G)	Reference EPA CCM 6th Edition, Section 1, Chapter 2, Equation2.8a. CRF based on 20 years and 3.75% interest rate.
Total Annualized Cost	(G)	$248,430	
Cost Effectiveness			
Baseline NO_X Emissions (tpy)		13.3	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		245,380	Average heat input to boiler during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.03	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		3.7	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		9.7	
Cost ($/ton NO_X removed)		$25,719	

[1] To provide a conservative NO_X removal cost estimate, the emissions guarantee for natural gas firing was used to calculate "controlled" emissions. However, this unit burns both fuel oil and natural gas during normal operations. Emissions during fuel oil firing would be higher than 0.03 lb/MMBtu, resulting in fewer tons of NO_X removed by this emissions control option and a higher $/ton cost.

U.S. Capitol Power Plant
Boiler 4, 5, 6, or 7 (CU-4, 5, 6, or 7)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB)

Cost Item	**Computational Method**	**Cost**	**Notes**
Purchased Equipment Costs			
Burner		$200,000 (A)	Project Cost Estimate Provided by AEI dated January 2022.
Direct Installation Costs			
Burner Installation		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Front Wall Modifications		$30,000	Project Cost Estimate Provided by AEI dated January 2022.
Gas Piping		$10,000	Project Cost Estimate Provided by AEI dated January 2022.
Oil Piping		$10,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Wiring		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Control/BMS Incorporation		$30,000	Project Cost Estimate Provided by AEI dated January 2022.
Electrical		$10,000	Project Cost Estimate Provided by AEI dated January 2022.
Total		$130,000 (B)	
Total Purchased Equipment and Direct	(A + B)	$330,000 (C)	
Indirect Installation Costs			
Engineering	0.10 (C)	$33,000	Project Cost Estimate Provided by AEI dated January 2022.
Construction and Field Expenses	0.04 (C)	$13,200	Project Cost Estimate Provided by AEI dated January 2022.
Contractor Fees	0.10 (C)	$33,000	Project Cost Estimate Provided by AEI dated January 2022.
Start-up	0.02 (C)	$6,600	Project Cost Estimate Provided by AEI dated January 2022.
Contingencies	0.03 (C)	$9,900	Project Cost Estimate Provided by AEI dated January 2022.
Total		$95,700 (D)	
AOC Required Indirect Installation Costs			
Contingency	0.20 (C + D)	$85,140	Project Cost Estimate Provided by AEI dated January 2022.
Construction Admin	0.04 (C + D)	$17,028	Project Cost Estimate Provided by AEI dated January 2022.
Government Test and QC	0.025 (C + D)	$10,643	Project Cost Estimate Provided by AEI dated January 2022.
AOC Construction Management	0.20 (C + D)	$85,140	Project Cost Estimate Provided by AEI dated January 2022.
AOC PM Fees	0.05 (C + D)	$21,285	Project Cost Estimate Provided by AEI dated January 2022.
Other	0.05 (C + D)	$21,285	Project Cost Estimate Provided by AEI dated January 2022.
Total		$240,521 (E)	
Total Installed Capital Cost	(C + D + E)	$666,221 (F)	
Direct Annual Costs		N/A	
Indirect Annual Costs			
Capital Recovery	CRF (F)	$47,943 (G)	Reference EPA CCM 6th Edition, Section 1, Chapter 2, Equation2.8a. CRF based on 20 years and 3.75% interest rate.
Total Annualized Cost	(G)	$47,943	

U.S. Capitol Power Plant
Boiler 4, 5, 6, or 7 (CU-4, 5, 6, or 7)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB)

Cost Item	Computational Method	Cost	Notes
Cost Effectiveness - Boiler 4			
Baseline NO_X Emissions (tpy)		6.0	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		114,915	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.05	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		2.9	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		3.1	
Cost ($/ton NO_X removed) - Boiler 4		$15,447	
Cost Effectiveness - Boiler 5			
Baseline NO_X Emissions (tpy)		3.1	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		57,745	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.05	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		1.4	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		1.6	
Cost ($/ton NO_X removed) - Boiler 5		$29,569	
Cost Effectiveness - Boiler 6			
Baseline NO_X Emissions (tpy)		4.5	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		89,337	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.05	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		2.2	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		2.3	
Cost ($/ton NO_X removed) - Boiler 6		$20,898	
Cost Effectiveness - Boiler 7			
Baseline NO_X Emissions (tpy)		3.7	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		69,930	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.05	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		1.7	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		1.9	
Cost ($/ton NO_X removed) - Boiler 7		$24,893	

[1] To provide a conservative NO_X removal cost estimate, the emissions guarantee for natural gas firing was used to calculate "controlled" emissions. However, this unit burns both fuel oil and natural gas during normal operations. Emissions during fuel oil firing would be higher than 0.05 lb/MMBtu, resulting in fewer tons of NO_X removed by this emissions control option and a higher $/ton cost.

U.S. Capitol Power Plant
Boiler 4, 5, 6, or 7 (CU-4, 5, 6, or 7)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB) and Flue Gas Recirculation (FGR)

Cost Item	Computational Method	Cost	Notes
Purchased Equipment Costs			
Burner		$225,000	Project Cost Estimate Provided by AEI dated January 2022.
FGR Fan		$25,000	
Total Equipment Costs		$250,000 (A)	
Direct Installation Costs			
Burner Installation		$20,000	Project Cost Estimate Provided by AEI dated January 2022.
Front Wall Modifications		$30,000	Project Cost Estimate Provided by AEI dated January 2022.
Gas Piping		$10,000	Project Cost Estimate Provided by AEI dated January 2022.
Oil Piping		$10,000	Project Cost Estimate Provided by AEI dated January 2022.
Breaching		$50,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Damper		$15,000	Project Cost Estimate Provided by AEI dated January 2022.
Control Wiring		$25,000	Project Cost Estimate Provided by AEI dated January 2022.
Control/BMS Incorporation		$30,000	Project Cost Estimate Provided by AEI dated January 2022.
Electrical		$25,000	Project Cost Estimate Provided by AEI dated January 2022.
Total		$215,000 (B)	
Total Purchased Equipment and Direct	(A + B)	$465,000 (C)	
Indirect Installation Costs			
Engineering	0.10 (C)	$46,500	Project Cost Estimate Provided by AEI dated January 2022.
Construction and Field Expenses	0.04 (C)	$18,600	Project Cost Estimate Provided by AEI dated January 2022.
Contractor Fees	0.10 (C)	$46,500	Project Cost Estimate Provided by AEI dated January 2022.
Start-up	0.02 (C)	$9,300	Project Cost Estimate Provided by AEI dated January 2022.
Contingencies	0.03 (C)	$13,950	Project Cost Estimate Provided by AEI dated January 2022.
Total		$134,850 (D)	
AOC Required Indirect Installation Costs			
Contingency	0.20 (C + D)	$119,970	Project Cost Estimate Provided by AEI dated January 2022.
Construction Admin	0.04 (C + D)	$23,994	Project Cost Estimate Provided by AEI dated January 2022.
Government Test and QC	0.025 (C + D)	$14,996	Project Cost Estimate Provided by AEI dated January 2022.
AOC Construction Management	0.20 (C + D)	$119,970	Project Cost Estimate Provided by AEI dated January 2022.
AOC PM Fees	0.05 (C + D)	$29,993	Project Cost Estimate Provided by AEI dated January 2022.
Other	0.05 (C + D)	$29,993	Project Cost Estimate Provided by AEI dated January 2022.
Total		$338,915 (E)	
Total Installed Capital Cost	(C + D + E)	$938,765 (F)	
Direct Annual Costs		N/A	
Indirect Annual Costs			
Capital Recovery	CRF (F)	$67,556 (G)	Reference EPA CCM 6th Edition, Section 1, Chapter 2, Equation2.8a. CRF based on 20 years and 3.75% interest rate.
Total Annualized Cost	(G)	$67,556	

U.S. Capitol Power Plant
Boiler 4, 5, 6, or 7 (CU-4, 5, 6, or 7)
Cost Analysis for Reducing NO_X Emissions by Installing Low NO_X Burners (LNB) and Flue Gas Recirculation (FGR)

Cost Item	Computational Method	Cost	Notes
Cost Effectiveness - Boiler 4			
Baseline NO_X Emissions (tpy)		6.0	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		114,915	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.03	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		1.7	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		4.3	
Cost (\$/ton NO_X removed) - Boiler 4		$15,885	
Cost Effectiveness - Boiler 5			
Baseline NO_X Emissions (tpy)		3.1	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		57,745	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.03	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		0.9	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		2.2	
Cost (\$/ton NO_X removed) - Boiler 5		$30,723	
Cost Effectiveness - Boiler 6			
Baseline NO_X Emissions (tpy)		4.5	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		89,337	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.03	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		1.3	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		3.2	
Cost (\$/ton NO_X removed) - Boiler 6		$21,194	
Cost Effectiveness - Boiler 7			
Baseline NO_X Emissions (tpy)		3.7	Baseline Actual Emissions is average of 2020-2021 observed emissions.
Unit Heat Input Rate (MMBtu/yr)		69,930	Average total heat input during 2020-2021 baseline.
Controlled NO_X Emissions Rate (lb/MMBtu)		0.03	Emissions guarantee when firing natural gas[1]
Controlled NO_X Emissions (tpy)		1.0	
Control Operating Time (%)		100%	
NO_X Emissions Removed (ton/yr)		2.6	
Cost (\$/ton NO_X removed) - Boiler 7		$25,733	

[1] To provide a conservative NO_X removal cost estimate, the emissions guarantee for natural gas firing was used to calculate "controlled" emissions. However, this unit burns both fuel oil and natural gas during normal operations. Emissions during fuel oil firing would be higher than 0.03 lb/MMBtu, resulting in fewer tons of NO_X removed by this emissions control option and a higher $/ton cost.

APPENDIX B. BOILER 3 PERFORMANCE TEST DATA

GAS Setting Data

Jobsite: Architect of the Capital **Max Heat Input:** **Fired Vessel:** Hoffman Combustion Engineering

ACE Project No.: USC200221 **Unit capacity:** 180 kPPH **Burner:** _

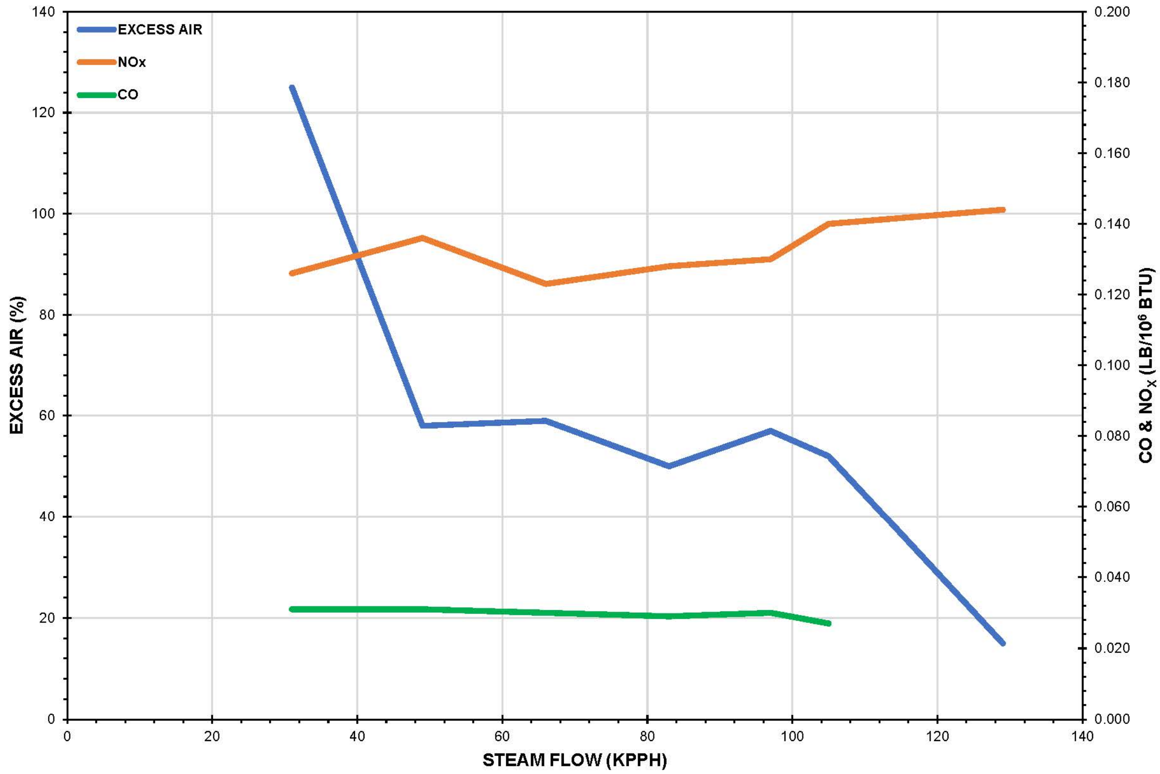
Date: 12/3/2020 **AOC CPP BOILER No. 3**

NOx Limit: 0.2 #/mmbtu **Systems Engr.:** Paul Merluzzi

Unit ID: 3 **Fuel:** Natural Gas **Burner Tech:** Jim Bolton

Before After Before After Before After Before After Before After Before After Before After Before After

Time (24 hr)	X	X		10:15		10:39		10:51		11:06		11:18		11:33		5:30
Curve Point	0		1	1	2	2	3	3	4	4	5	5	6	6	6	6
Boiler Master output	15		20	20	30	30	40	40	50	50	60	60	70	70	80	80
Gas Valve Pos.	30		33.6	33.2	39	39	44	45.5	51	51.3	57.5	56.2	61	63	61	67
Windbox press., "w.c.	0.38		0.44	0.66	0.58	1.26	1.08	1.68	1.41	1.93	1.72	2.65	2.15	3.05	2.15	2.15
Furnace pressure., "wc	-0.27		-0.19	-0.21	-0.18	-0.15	-0.12	-0.13	-0.18	-0.31	-0.23	-0.14	-0.16	-0.3	-0.16	-0.16
Throat DP	0.65		0.63	0.87	0.76	1.41	1.2	1.81	1.59	2.24	1.95	2.79	2.31	3.35	2.31	2.31
Gas supply, psig	18.36		18.3	18.1	18.24	17.9	18.1	17.8	17.8	17.6	17.62	17.3	17.3	17	17.3	16.7
Gas @ burner, psig	0.15		0.24	0.22	0.45	0.45	0.82	0.84	1.27	1.27	1.78	1.84	2.41	2.41	2.41	2.87
Gas flow, kscfh	30		39	38	58	58	78	79	98	97	117	118	137	136	137	150
FD Damper	42		42	41	43.6	46	52	53	58	57	64	64	71	70	71	98
Burner 1 Register Setting	2.5		2.5	18	2.5	31.35	2.5	34.46	3	41.74	3	49.51	3.5	57.75	3.5	100
Burner 2 Register Setting/Air Dampe	3		3	18	3.5	31.35	3.5	34.46	3.5	41.74	4.2	49.51	4.5	57.75	4.5	100
Burner 3 Register Setting/Air Dampe	3.5		3.5	18	3.5	31.35	4	34.46	4.5	41.74	5	49.51	5.2	57.75	5.2	100
Burner 4 Register Setting/Air Dampe	2		2	18	2.2	31.35	2.5	34.46	3	41.74	3	49.51	3.2	57.75	3.2	100
ID Damper	54		48	57	61.3	67	75.3	77	79	74	77.5	78	79	78	79	89.4
ID Fan RPM	461		413	421	406	400	437	433	487	535	618	628	707	724	707	824
Steam Pressure, psig	188		189	188.85	189	190	193	193.5	192	198.3	196	198.15	206	207.3	206	182.05
Steam flow, kpph	24		33	31	46	49	64	66	81	83	96	97	108	105	108	129
Installed Stack Oxygen	12.31		9.7	7.9	5.21	6.1	5.02	5.2	3.96	3.8	3.64	3.4	3.41	3.3	3.41	5.6
Combustion Air Flow, CFM	10732		10777	12575	11977	16793	16513	21235	19551	24043	22721	28816	26562	32880	26562	44097
O_2 %, dry Testo	12.68		10.5	12	6.93	8.01	6.98	8.1	5.56	8	4.98	7.90	5.27	7.5	5.27	2.93
NOx, ppm, raw Testo	41.50		58.90	51.90	89.90	80.90	85.50	72.60	97.70	76.50	100.30	78.40	106.30	86.90	106.30	119.50
NO, ppm, raw Testo	29.00		56.00	49.00	87.00	78.00	83.00	70.00	95.00	74.00	98.00	76.00	104.00	85.00	104.00	117.00
NO2, ppm, raw Testo	12.5		2.9	2.9	2.9	2.9	2.5	2.6	2.7	2.5	2.3	2.4	2.3	1.9	2.3	2.5
CO, ppm, raw Testo	4		0	21	0	30	0	29	0	28	0	30	0	27	0	0
CO_2 %, dry Testo	4.64		5.85	4.87	7.84	6.92	7.81	6.7	8.6	7.2	8.93	7.2	8.76	7.3	8.76	8.76
*Excess air, % **	142.97		93.83	125.09	46.23	57.87	46.72	58.93	33.80	57.75	29.15	56.59	31.44	52.14	31.44	15.22
*NOx, #/MMBtu **	0.109		0.123	0.126	0.139	0.136	0.133	0.123	0.138	0.128	0.136	0.130	0.147	0.140	0.147	0.144
*CO, #/MMBtu **	0.006		0.000	0.031	0.000	0.031	0.000	0.030	0.000	0.029	0.000	0.030	0.000	0.027	0.000	0.000
Efficiency	80.0		78.0	83.4	78.0	85.3	77.0	85.2	79.0	85.2	79.0	85.0	77.0	84.8	77.0	76.0
Econ Inlet Temp., Deg. F	397.0		400.8	386.0	410.0	396.0	434.0	419.0	460.0	450.0	493.0	484.0	524.0	505.0	524.0	551.0
Econ Out Temp., Deg. F	192.0		191.0	227.0	190.5	219.0	177.0	217.0	178.0	218.0	184.0	223.0	191.0	227.0	191.0	239.0
Stack Temperature, Deg F				272		271		279		289		303		313		
Comb. air temp, deg F	64		64	64	64	64	63	63	63	63	62	62	61	61	61	61
FW Flow GPM	43		78	68	124	123	149	139	195	164	208	209	236	218	236	245
FW Flow KPPH	21.5		39	34	62	61.5	74.5	69.5	97.5	82	104	104.5	118	109	118	122.5
O2 Trim %	50.0%		50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
FW Inlet Temp. to Econ	233		233.0	233.0	233.0	233.0	233.0	233.0	234.0	234.0	234.0	234.0	233.0	233.0	233.0	233.0
Opacity, %	5.2		5.1	4.2	5.7	4.1	5.4	3.9	4.9	3.9	5.1	4.0	5.3	4.3	5.3	5.8



EXCESS AIR
NOx
CO
EXCESS AIR (%)
CO & NOX (LB/10⁶ BTU)
STEAM FLOW (KPPH)
140
120
100
80
60
40
20
0
0.200
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
0
20
40
60
80
100
120
140

APPENDIX C. UPL CALCULATIONS

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
1/1/2019	0.107	-2.2349
1/2/2019	0.109	-2.2164
1/3/2019	0.109	-2.2164
1/4/2019	0.108	-2.2256
1/5/2019	0.107	-2.2349
1/6/2019	0.113	-2.1804
1/7/2019	0.112	-2.1893
1/8/2019	0.104	-2.2634
1/9/2019	0.115	-2.1628
1/10/2019	0.114	-2.1716
1/11/2019	0.116	-2.1542
1/12/2019	0.116	-2.1542
1/13/2019	0.114	-2.1716
1/14/2019	0.114	-2.1716
1/15/2019	0.116	-2.1542
1/16/2019	0.114	-2.1716
1/17/2019	0.115	-2.1628
1/18/2019	0.113	-2.1804
1/19/2019	0.114	-2.1716
1/20/2019	0.113	-2.1804
1/21/2019	0.116	-2.1542
1/22/2019	0.12	-2.1203
1/23/2019	0.118	-2.1371
1/24/2019	0.109	-2.2164
1/25/2019	0.117	-2.1456
1/26/2019	0.117	-2.1456
1/27/2019	0.121	-2.1120
1/28/2019	0.121	-2.1120
1/29/2019	0.120	-2.1203
1/30/2019	0.120	-2.1203
1/31/2019	0.121	-2.1120

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
2/1/2019	0.118	-2.1371
2/2/2019	0.118	-2.1371
2/3/2019	0.117	-2.1456
2/4/2019	0.114	-2.1716
2/5/2019	0.111	-2.1982
2/6/2019	0.113	-2.1804
2/7/2019	0.111	-2.1982
2/8/2019	0.114	-2.1716
2/9/2019	0.122	-2.1037
2/10/2019	0.118	-2.1371
2/11/2019	0.113	-2.1804
2/12/2019	0.114	-2.1716
2/13/2019	0.116	-2.1542
2/14/2019	0.117	-2.1456
2/15/2019	0.118	-2.1371
2/16/2019	0.119	-2.1286
2/17/2019	0.116	-2.1542
2/18/2019	0.116	-2.1542
2/19/2019	0.119	-2.1286
2/20/2019	0.115	-2.1628
2/21/2019	0.115	-2.1628
2/22/2019	0.119	-2.1286
2/23/2019	0.118	-2.1371
2/24/2019	0.116	-2.1542
2/25/2019	0.121	-2.1120
2/26/2019	0.122	-2.1037
2/27/2019	0.118	-2.1371
2/28/2019	0.119	-2.1286

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
3/1/2019	0.117	-2.1456
3/2/2019	0.114	-2.1716
3/3/2019	0.118	-2.1371
3/4/2019	0.119	-2.1286
3/5/2019	0.122	-2.1037
3/6/2019	0.123	-2.0956
3/7/2019	0.123	-2.0956
3/8/2019	0.118	-2.1371
3/9/2019	0.119	-2.1286
3/10/2019	0.112	-2.1893
3/11/2019	0.117	-2.1456
3/12/2019	0.118	-2.1371
3/13/2019	0.117	-2.1456
3/14/2019	0.114	-2.1716
3/15/2019	0.107	-2.2349
3/16/2019	0.119	-2.1286
3/17/2019	0.119	-2.1286
3/18/2019	0.118	-2.1371
3/19/2019	0.12	-2.1203
3/20/2019	0.119	-2.1286
3/21/2019	0.111	-2.1982
3/22/2019	0.113	-2.1804
3/23/2019	0.12	-2.1203
3/24/2019	0.121	-2.1120
3/25/2019	0.112	-2.1893
3/26/2019	0.117	-2.1456
3/27/2019	0.119	-2.1286
3/28/2019	0.114	-2.1716
3/29/2019	0.105	-2.2538
3/30/2019	0.114	-2.1716
3/31/2019	0.115	-2.1628

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
4/1/2019	0.122	-2.1037
4/2/2019	0.12	-2.1203
4/3/2019	0.121	-2.1120
4/4/2019	0.119	-2.1286
4/5/2019	0.113	-2.1804
4/6/2019	0.112	-2.1893
4/7/2019	0.108	-2.2256
4/8/2019	0.101	-2.2926
4/9/2019	0.104	-2.2634
4/10/2019	0.115	-2.1628
4/11/2019	0.108	-2.2256
4/12/2019	0.1	-2.3026
4/13/2019	0.096	-2.3434
4/14/2019	0.094	-2.3645
4/15/2019	0.105	-2.2538
4/16/2019	0.116	-2.1542
4/17/2019	0.108	-2.2256
4/18/2019	0.104	-2.2634
4/19/2019	0.093	-2.3752
4/20/2019	0.1	-2.3026
4/21/2019	0.105	-2.2538
4/22/2019	0.105	-2.2538
4/23/2019	0.106	-2.2443
4/24/2019	0.108	-2.2256
4/25/2019	0.108	-2.2256
4/26/2019	0.099	-2.3126
4/27/2019	0.113	-2.1804
4/28/2019	0.106	-2.2443
4/29/2019	0.109	-2.2164
4/30/2019	0.1	-2.3026

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
5/1/2019	0.1	-2.3026
5/2/2019	0.094	-2.3645
5/3/2019	0.089	-2.4191
5/4/2019	0.094	-2.3645
5/5/2019	0.094	-2.3645
5/6/2019	0.1	-2.3026
5/7/2019	0.096	-2.3434
5/8/2019	0.097	-2.3330
5/9/2019	0.096	-2.3434
5/10/2019	0.094	-2.3645
5/11/2019	0.098	-2.3228
5/12/2019	0.099	-2.3126
5/13/2019	0.104	-2.2634
5/14/2019	0.105	-2.2538
5/15/2019	0.104	-2.2634
5/16/2019	0.099	-2.3126
5/17/2019	0.094	-2.3645
5/18/2019	0.093	-2.3752
5/19/2019	0.092	-2.3860
5/20/2019	0.098	-2.3228
5/21/2019	0.105	-2.2538
5/22/2019	0.105	-2.2538
5/23/2019	0.094	-2.3645
5/24/2019	0.098	-2.3228
5/25/2019	0.092	-2.3860
5/26/2019	0.087	-2.4418
5/27/2019	0.091	-2.3969
5/28/2019	0.086	-2.4534
5/29/2019	0.084	-2.4769
5/30/2019	0.088	-2.4304
5/31/2019	0.091	-2.3969

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
6/1/2019	0.095	-2.3539
6/2/2019	0.09	-2.4079
6/3/2019	0.104	-2.2634
6/4/2019	0.106	-2.2443
6/5/2019	0.089	-2.4191
6/6/2019	0.085	-2.4651
6/7/2019	0.087	-2.4418
6/8/2019	0.096	-2.3434
6/9/2019	0.092	-2.3860
6/10/2019	0.088	-2.4304
6/11/2019	0.097	-2.3330
6/12/2019	0.098	-2.3228
6/13/2019	0.091	-2.3969
6/14/2019	0.102	-2.2828
6/15/2019	0.098	-2.3228
6/16/2019	0.09	-2.4079
6/17/2019	0.086	-2.4534
6/18/2019	0.085	-2.4651
6/19/2019	0.084	-2.4769
6/20/2019	0.087	-2.4418
6/21/2019	0.092	-2.3860
6/22/2019	0.088	-2.4304
6/23/2019	0.083	-2.4889
6/24/2019	0.078	-2.5510
6/25/2019	0.075	-2.5903
6/26/2019	0.084	-2.4769
6/27/2019	0.087	-2.4418
6/28/2019	0.086	-2.4534
6/29/2019	0.086	-2.4534
6/30/2019	0.091	-2.3969

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
7/1/2019	0.09	-2.4079
7/2/2019	0.063	-2.7646
7/3/2019	0.024	-3.7297
7/4/2019	0.016	-4.1352
7/5/2019	0.018	-4.0174
7/6/2019	0.021	-3.8632
7/7/2019	0.029	-3.5405
7/8/2019	0.024	-3.7297
7/9/2019	0.018	-4.0174
7/10/2019	0.02	-3.9120
7/11/2019	0.022	-3.8167
7/12/2019	0.027	-3.6119
7/13/2019	0.022	-3.8167
7/14/2019	0.023	-3.7723
7/15/2019	0.049	-3.0159
7/16/2019	0.065	-2.7334
7/17/2019	0.049	-3.0159
7/18/2019	0.026	-3.6497
7/19/2019	0.039	-3.2442
7/20/2019	0.018	-4.0174
7/21/2019	0.029	-3.5405
7/22/2019	0.02	-3.9120
7/23/2019	0.023	-3.7723
7/24/2019	0.019	-3.9633
7/25/2019	0.024	-3.7297
7/26/2019	0.038	-3.2702
7/27/2019	0.043	-3.1466
7/28/2019	0.039	-3.2442
7/29/2019	0.042	-3.1701
7/30/2019	0.065	-2.7334
7/31/2019	0.063	-2.7646

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
8/1/2019	0.062	-2.7806
8/2/2019	0.056	-2.8824
8/3/2019	0.025	-3.6889
8/4/2019	0.024	-3.7297
8/5/2019	0.029	-3.5405
8/6/2019	0.031	-3.4738
8/7/2019	0.047	-3.0576
8/8/2019	0.049	-3.0159
8/9/2019	0.036	-3.3242
8/10/2019	0.034	-3.3814
8/11/2019	0.055	-2.9004
8/12/2019	0.042	-3.1701
8/13/2019	0.022	-3.8167
8/14/2019	0.028	-3.5756
8/15/2019	0.03	-3.5066
8/16/2019	0.049	-3.0159
8/17/2019	0.024	-3.7297
8/18/2019	0.029	-3.5405
8/19/2019	0.031	-3.4738
8/20/2019	0.055	-2.9004
8/21/2019	0.037	-3.2968
8/22/2019	0.039	-3.2442
8/23/2019	0.02	-3.9120
8/24/2019	0.022	-3.8167
8/25/2019	0.051	-2.9759
8/26/2019	0.053	-2.9375
8/27/2019	0.08	-2.5257
8/28/2019	0.075	-2.5903
8/29/2019	0.083	-2.4889
8/30/2019	0.08	-2.5257
8/31/2019	0.079	-2.5383

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
9/1/2019	0.039	-3.2442
9/2/2019	0.053	-2.9375
9/3/2019	0.032	-3.4420
9/4/2019	0.027	-3.6119
9/5/2019	0.092	-2.3860
9/6/2019	0.134	-2.0099
9/7/2019	0.132	-2.0250
9/8/2019	0.137	-1.9878
9/9/2019	0.139	-1.9733
9/10/2019	0.133	-2.0174
9/11/2019	0.126	-2.0715
9/12/2019	0.121	-2.1120
9/13/2019	0.12	-2.1203
9/14/2019	0.117	-2.1456
9/15/2019	0.12	-2.1203
9/16/2019	0.118	-2.1371
9/17/2019	0.115	-2.1628
9/18/2019	0.129	-2.0479
9/19/2019	0.134	-2.0099
9/20/2019	0.108	-2.2256
9/21/2019	0.085	-2.4651
9/22/2019	0.082	-2.5010
9/23/2019	0.088	-2.4304
9/24/2019	0.091	-2.3969
9/25/2019	0.1	-2.3026
9/26/2019	0.097	-2.3330
9/27/2019	0.097	-2.3330
9/28/2019	0.088	-2.4304
9/29/2019	0.089	-2.4191
9/30/2019	0.094	-2.3645

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
10/1/2019	0.093	-2.3752
10/2/2019	0.089	-2.4191
10/3/2019	0.089	-2.4191
10/4/2019	0.1	-2.3026
10/5/2019	0.102	-2.2828
10/6/2019	0.092	-2.3860
10/7/2019	0.095	-2.3539
10/8/2019	0.103	-2.2730
10/9/2019	0.102	-2.2828
10/10/2019	0.103	-2.2730
10/11/2019	0.107	-2.2349
10/12/2019	0.101	-2.2926
10/13/2019	0.103	-2.2730
10/14/2019	0.099	-2.3126
10/15/2019	0.096	-2.3434
10/16/2019	0.092	-2.3860
10/17/2019	0.098	-2.3228
10/18/2019	0.098	-2.3228
10/19/2019	0.097	-2.3330
10/20/2019	0.091	-2.3969
10/21/2019	0.096	-2.3434
10/22/2019	0.088	-2.4304
10/23/2019	0.099	-2.3126
10/24/2019	0.101	-2.2926
10/25/2019	0.098	-2.3228
10/26/2019	0.1	-2.3026
10/27/2019	0.097	-2.3330
10/28/2019	0.099	-2.3126
10/29/2019	0.093	-2.3752
10/30/2019	0.092	-2.3860
10/31/2019	0.087	-2.4418

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
11/1/2019	0.108	-2.2256
11/2/2019	0.108	-2.2256
11/3/2019	0.106	-2.2443
11/4/2019	0.107	-2.2349
11/5/2019	0.105	-2.2538
11/6/2019	0.106	-2.2443
11/7/2019	0.103	-2.2730
11/8/2019	0.113	-2.1804
11/9/2019	0.114	-2.1716
11/10/2019	0.109	-2.2164
11/11/2019	0.108	-2.2256
11/12/2019	0.11	-2.2073
11/13/2019	0.118	-2.1371
11/14/2019	0.115	-2.1628
11/15/2019	0.105	-2.2538
11/16/2019	0.113	-2.1804
11/17/2019	0.117	-2.1456
11/18/2019	0.111	-2.1982
11/19/2019	0.11	-2.2073
11/20/2019	0.112	-2.1893
11/21/2019	0.113	-2.1804
11/22/2019	0.109	-2.2164
11/23/2019	0.112	-2.1893
11/24/2019	0.112	-2.1893
11/25/2019	0.113	-2.1804
11/26/2019	0.11	-2.2073
11/27/2019	0.108	-2.2256
11/28/2019	0.114	-2.1716
11/29/2019	0.117	-2.1456
11/30/2019	0.117	-2.1456

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
12/1/2019	0.111	-2.1982
12/2/2019	0.111	-2.1982
12/3/2019	0.115	-2.1628
12/4/2019	0.113	-2.1804
12/5/2019	0.116	-2.1542
12/6/2019	0.115	-2.1628
12/7/2019	0.118	-2.1371
12/8/2019	0.115	-2.1628
12/9/2019	0.109	-2.2164
12/10/2019	0.104	-2.2634
12/11/2019	0.115	-2.1628
12/12/2019	0.117	-2.1456
12/13/2019	0.111	-2.1982
12/14/2019	0.109	-2.2164
12/15/2019	0.113	-2.1804
12/16/2019	0.112	-2.1893
12/17/2019	0.113	-2.1804
12/18/2019	0.117	-2.1456
12/19/2019	0.118	-2.1371
12/20/2019	0.116	-2.1542
12/21/2019	0.116	-2.1542
12/22/2019	0.116	-2.1542
12/23/2019	0.114	-2.1716
12/24/2019	0.114	-2.1716
12/25/2019	0.113	-2.1804
12/26/2019	0.111	-2.1982
12/27/2019	0.107	-2.2349
12/28/2019	0.109	-2.2164
12/29/2019	0.106	-2.2443
12/30/2019	0.102	-2.2828
12/31/2019	0.111	-2.1982

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
1/1/2020	0.114	-2.1716
1/2/2020	0.115	-2.1628
1/3/2020	0.106	-2.2443
1/4/2020	0.105	-2.2538
1/5/2020	0.114	-2.1716
1/6/2020	0.114	-2.1716
1/7/2020	0.112	-2.1893
1/8/2020	0.116	-2.1542
1/9/2020	0.115	-2.1628
1/10/2020	0.111	-2.1982
1/11/2020	0.101	-2.2926
1/12/2020	0.102	-2.2828
1/13/2020	0.108	-2.2256
1/14/2020	0.107	-2.2349
1/15/2020	0.106	-2.2443
1/16/2020	0.11	-2.2073
1/17/2020	0.11	-2.2073
1/18/2020	0.114	-2.1716
1/19/2020	0.111	-2.1982
1/20/2020	0.112	-2.1893
1/21/2020	0.113	-2.1804
1/22/2020	0.116	-2.1542
1/23/2020	0.116	-2.1542
1/24/2020	0.114	-2.1716
1/25/2020	0.106	-2.2443
1/26/2020	0.11	-2.2073
1/27/2020	0.109	-2.2164
1/28/2020	0.109	-2.2164
1/29/2020	0.112	-2.1893
1/30/2020	0.114	-2.1716
1/31/2020	0.11	-2.2073

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
2/1/2020	0.109	-2.2164
2/2/2020	0.109	-2.2164
2/3/2020	0.109	-2.2164
2/4/2020	0.103	-2.2730
2/5/2020	0.103	-2.2730
2/6/2020	0.105	-2.2538
2/7/2020	0.104	-2.2634
2/8/2020	0.111	-2.1982
2/9/2020	0.110	-2.2073
2/10/2020	0.105	-2.2538
2/11/2020	0.101	-2.2926
2/12/2020	0.108	-2.2256
2/13/2020	0.102	-2.2828
2/14/2020	0.109	-2.2164
2/15/2020	0.113	-2.1804
2/16/2020	0.115	-2.1628
2/17/2020	0.113	-2.1804
2/18/2020	0.109	-2.2164
2/19/2020	0.111	-2.1982
2/20/2020	0.113	-2.1804
2/21/2020	0.115	-2.1628
2/22/2020	0.115	-2.1628
2/23/2020	0.114	-2.1716
2/24/2020	0.112	-2.1893
2/25/2020	0.104	-2.2634
2/26/2020	0.103	-2.2730
2/27/2020	0.112	-2.1893
2/28/2020	0.112	-2.1893
2/29/2020	0.111	-2.1982

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
3/1/2020	0.114	-2.1716
3/2/2020	0.111	-2.1982
3/3/2020	0.104	-2.2634
3/4/2020	0.111	-2.1982
3/5/2020	0.113	-2.1804
3/6/2020	0.111	-2.1982
3/7/2020	0.115	-2.1628
3/8/2020	0.114	-2.1716
3/9/2020	0.111	-2.1982
3/10/2020	0.097	-2.3330
3/11/2020	0.105	-2.2538
3/12/2020	0.106	-2.2443
3/13/2020	0.108	-2.2256
3/14/2020	0.113	-2.1804
3/15/2020	0.106	-2.2443
3/16/2020	0.107	-2.2349
3/17/2020	0.104	-2.2634
3/18/2020	0.107	-2.2349
3/19/2020	0.096	-2.3434
3/20/2020	0.095	-2.3539
3/21/2020	0.101	-2.2926
3/22/2020	0.105	-2.2538
3/23/2020	0.102	-2.2828
3/24/2020	0.104	-2.2634
3/25/2020	0.103	-2.2730
3/26/2020	0.103	-2.2730
3/27/2020	0.102	-2.2828
3/28/2020	0.097	-2.3330
3/29/2020	0.099	-2.3126
3/30/2020	0.105	-2.2538
3/31/2020	0.105	-2.2538

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
4/1/2020	0.105	-2.2538
4/2/2020	0.11	-2.2073
4/3/2020	0.109	-2.2164
4/4/2020	0.103	-2.2730
4/5/2020	0.101	-2.2926
4/6/2020	0.104	-2.2634
4/7/2020	0.099	-2.3126
4/8/2020	0.099	-2.3126
4/9/2020	0.103	-2.2730
4/10/2020	0.109	-2.2164
4/11/2020	0.11	-2.2073
4/12/2020	0.101	-2.2926
4/13/2020	0.096	-2.3434
4/14/2020	0.108	-2.2256
4/15/2020	0.109	-2.2164
4/16/2020	0.111	-2.1982
4/17/2020	0.109	-2.2164
4/18/2020	0.106	-2.2443
4/19/2020	0.108	-2.2256
4/20/2020	0.104	-2.2634
4/21/2020	0.105	-2.2538
4/22/2020	0.112	-2.1893
4/23/2020	0.104	-2.2634
4/24/2020	0.099	-2.3126
4/25/2020	0.102	-2.2828
4/26/2020	0.1	-2.3026
4/27/2020	0.104	-2.2634
4/28/2020	0.104	-2.2634
4/29/2020	0.103	-2.2730
4/30/2020	0.098	-2.3228

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
5/1/2020	0.113	-2.1804
5/2/2020	0.102	-2.2828
5/3/2020	0.094	-2.3645
5/4/2020	0.093	-2.3752
5/5/2020	0.1	-2.3026
5/6/2020	0.113	-2.1804
5/7/2020	0.109	-2.2164
5/8/2020	0.111	-2.1982
5/9/2020	0.11	-2.2073
5/10/2020	0.11	-2.2073
5/11/2020	0.114	-2.1716
5/12/2020	0.114	-2.1716
5/13/2020	0.116	-2.1542
5/14/2020	0.114	-2.1716
5/15/2020	0.113	-2.1804
5/16/2020	0.107	-2.2349
5/17/2020	0.107	-2.2349
5/18/2020	0.108	-2.2256
5/19/2020	0.11	-2.2073
5/20/2020	0.109	-2.2164
5/21/2020	0.114	-2.1716
5/22/2020	0.104	-2.2634
5/23/2020	0.104	-2.2634
5/24/2020	0.101	-2.2926
5/25/2020	0.099	-2.3126
5/26/2020	0.096	-2.3434
5/27/2020	0.093	-2.3752
5/28/2020	0.1	-2.3026
5/29/2020	0.093	-2.3752
5/30/2020	0.095	-2.3539
5/31/2020	0.098	-2.3228

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
6/1/2020	0.105	-2.2538
6/2/2020	0.098	-2.3228
6/3/2020	0.089	-2.4191
6/4/2020	0.087	-2.4418
6/5/2020	0.087	-2.4418
6/6/2020	0.093	-2.3752
6/7/2020	0.104	-2.2634
6/8/2020	0.105	-2.2538
6/9/2020	0.093	-2.3752
6/10/2020	0.087	-2.4418
6/11/2020	0.092	-2.3860
6/12/2020	0.105	-2.2538
6/13/2020	0.106	-2.2443
6/14/2020	0.105	-2.2538
6/15/2020	0.104	-2.2634
6/16/2020	0.104	-2.2634
6/17/2020	0.096	-2.3434
6/18/2020	0.094	-2.3645
6/19/2020	0.093	-2.3752
6/20/2020	0.091	-2.3969
6/21/2020	0.092	-2.3860
6/22/2020	0.092	-2.3860
6/23/2020	0.091	-2.3969
6/24/2020	0.097	-2.3330
6/25/2020	0.095	-2.3539
6/26/2020	0.097	-2.3330
6/27/2020	0.09	-2.4079
6/28/2020	0.09	-2.4079
6/29/2020	0.094	-2.3645
6/30/2020	0.096	-2.3434

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
7/1/2020	0.091	-2.3969
7/2/2020	0.095	-2.3539
7/3/2020	0.095	-2.3539
7/4/2020	0.093	-2.3752
7/5/2020	0.087	-2.4418
7/6/2020	0.088	-2.4304
7/7/2020	0.089	-2.4191
7/8/2020	0.091	-2.3969
7/9/2020	0.088	-2.4304
7/10/2020	0.087	-2.4418
7/11/2020	0.091	-2.3969
7/12/2020	0.094	-2.3645
7/13/2020	0.094	-2.3645
7/14/2020	0.098	-2.3228
7/15/2020	0.098	-2.3228
7/16/2020	0.117	-2.1456
7/17/2020	0.094	-2.3645
7/18/2020	0.111	-2.1982
7/19/2020	0.104	-2.2634
7/20/2020	0.101	-2.2926
7/21/2020	0.103	-2.2730
7/22/2020	0.091	-2.3969
7/23/2020	0.035	-3.3524
7/24/2020	0.03	-3.5066
7/25/2020	0.028	-3.5756
7/26/2020	0.033	-3.4112
7/27/2020	0.028	-3.5756
7/28/2020	0.042	-3.1701
7/29/2020	0.046	-3.0791
7/30/2020	0.043	-3.1466
7/31/2020	0.035	-3.3524

West Stack NO_X Emissions		
Date	**NO_X (lb/MMBtu)**	**Ln of Raw Data**
8/1/2020	0.026	-3.6497
8/2/2020		
8/3/2020		
8/4/2020		
8/5/2020		
8/6/2020		
8/7/2020	0.058	-2.8473
8/8/2020	0.044	-3.1236
8/9/2020	0.075	-2.5903
8/10/2020	0.09	-2.4079
8/11/2020	0.086	-2.4534
8/12/2020	0.089	-2.4191
8/13/2020	0.09	-2.4079
8/14/2020	0.091	-2.3969
8/15/2020	0.095	-2.3539
8/16/2020	0.094	-2.3645
8/17/2020	0.095	-2.3539
8/18/2020	0.098	-2.3228
8/19/2020	0.096	-2.3434
8/20/2020	0.099	-2.3126
8/21/2020	0.094	-2.3645
8/22/2020	0.092	-2.3860
8/23/2020	0.093	-2.3752
8/24/2020	0.092	-2.3860
8/25/2020	0.096	-2.3434
8/26/2020	0.1	-2.3026
8/27/2020	0.095	-2.3539
8/28/2020	0.093	-2.3752
8/29/2020	0.09	-2.4079
8/30/2020	0.102	-2.2828
8/31/2020	0.097	-2.3330

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
9/1/2020	0.044	-3.1236
9/2/2020	0.079	-2.5383
9/3/2020	0.089	-2.4191
9/4/2020	0.091	-2.3969
9/5/2020	0.102	-2.2828
9/6/2020	0.097	-2.3330
9/7/2020	0.096	-2.3434
9/8/2020	0.09	-2.4079
9/9/2020	0.084	-2.4769
9/10/2020	0.083	-2.4889
9/11/2020	0.087	-2.4418
9/12/2020	0.094	-2.3645
9/13/2020	0.093	-2.3752
9/14/2020	0.096	-2.3434
9/15/2020	0.102	-2.2828
9/16/2020	0.097	-2.3330
9/17/2020	0.09	-2.4079
9/18/2020	0.096	-2.3434
9/19/2020	0.106	-2.2443
9/20/2020	0.105	-2.2538
9/21/2020	0.105	-2.2538
9/22/2020	0.103	-2.2730
9/23/2020	0.102	-2.2828
9/24/2020	0.094	-2.3645
9/25/2020	0.092	-2.3860
9/26/2020	0.091	-2.3969
9/27/2020	0.088	-2.4304
9/28/2020	0.089	-2.4191
9/29/2020	0.09	-2.4079
9/30/2020	0.099	-2.3126

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
10/1/2020	0.101	-2.2926
10/2/2020	0.103	-2.2730
10/3/2020	0.104	-2.2634
10/4/2020	0.102	-2.2828
10/5/2020	0.102	-2.2828
10/6/2020	0.1	-2.3026
10/7/2020	0.099	-2.3126
10/8/2020	0.107	-2.2349
10/9/2020	0.103	-2.2730
10/10/2020	0.096	-2.3434
10/11/2020	0.091	-2.3969
10/12/2020	0.094	-2.3645
10/13/2020	0.099	-2.3126
10/14/2020	0.101	-2.2926
10/15/2020	0.096	-2.3434
10/16/2020	0.11	-2.2073
10/17/2020	0.114	-2.1716
10/18/2020	0.111	-2.1982
10/19/2020	0.106	-2.2443
10/20/2020	0.103	-2.2730
10/21/2020	0.097	-2.3330
10/22/2020	0.098	-2.3228
10/23/2020	0.099	-2.3126
10/24/2020	0.103	-2.2730
10/25/2020	0.105	-2.2538
10/26/2020	0.109	-2.2164
10/27/2020	0.114	-2.1716
10/28/2020	0.108	-2.2256
10/29/2020	0.112	-2.1893
10/30/2020	0.123	-2.0956
10/31/2020	0.125	-2.0794

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
11/1/2020	0.118	-2.1371
11/2/2020	0.125	-2.0794
11/3/2020	0.123	-2.0956
11/4/2020	0.119	-2.1286
11/5/2020	0.116	-2.1542
11/6/2020	0.114	-2.1716
11/7/2020	0.116	-2.1542
11/8/2020	0.11	-2.2073
11/9/2020	0.121	-2.1120
11/10/2020	0.119	-2.1286
11/11/2020	0.124	-2.0875
11/12/2020	0.12	-2.1203
11/13/2020	0.124	-2.0875
11/14/2020	0.128	-2.0557
11/15/2020	0.13	-2.0402
11/16/2020	0.141	-1.9590
11/17/2020	0.129	-2.0479
11/18/2020	0.127	-2.0636
11/19/2020	0.129	-2.0479
11/20/2020	0.121	-2.1120
11/21/2020	0.1	-2.3026
11/22/2020	0.099	-2.3126
11/23/2020	0.102	-2.2828
11/24/2020	0.111	-2.1982
11/25/2020	0.104	-2.2634
11/26/2020	0.093	-2.3752
11/27/2020	0.096	-2.3434
11/28/2020	0.096	-2.3434
11/29/2020	0.099	-2.3126
11/30/2020	0.117	-2.1456

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
12/1/2020	0.12	-2.1203
12/2/2020	0.119	-2.1286
12/3/2020	0.094	-2.3645
12/4/2020	0.093	-2.3752
12/5/2020	0.111	-2.1982
12/6/2020	0.113	-2.1804
12/7/2020	0.113	-2.1804
12/8/2020	0.115	-2.1628
12/9/2020	0.115	-2.1628
12/10/2020	0.112	-2.1893
12/11/2020	0.103	-2.2730
12/12/2020	0.107	-2.2349
12/13/2020	0.108	-2.2256
12/14/2020	0.109	-2.2164
12/15/2020	0.113	-2.1804
12/16/2020	0.112	-2.1893
12/17/2020	0.112	-2.1893
12/18/2020	0.112	-2.1893
12/19/2020	0.11	-2.2073
12/20/2020	0.112	-2.1893
12/21/2020	0.11	-2.2073
12/22/2020	0.11	-2.2073
12/23/2020	0.114	-2.1716
12/24/2020	0.103	-2.2730
12/25/2020	0.11	-2.2073
12/26/2020	0.115	-2.1628
12/27/2020	0.114	-2.1716
12/28/2020	0.111	-2.1982
12/29/2020	0.113	-2.1804
12/30/2020	0.114	-2.1716
12/31/2020	0.108	-2.2256

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
1/1/2021	0.112	-2.1893
1/2/2021	0.109	-2.2164
1/3/2021	0.11	-2.2073
1/4/2021	0.111	-2.1982
1/5/2021	0.11	-2.2073
1/6/2021	0.111	-2.1982
1/7/2021	0.113	-2.1804
1/8/2021	0.114	-2.1716
1/9/2021	0.115	-2.1628
1/10/2021	0.113	-2.1804
1/11/2021	0.111	-2.1982
1/12/2021	0.114	-2.1716
1/13/2021	0.106	-2.2443
1/14/2021	0.115	-2.1628
1/15/2021	0.114	-2.1716
1/16/2021	0.108	-2.2256
1/17/2021	0.111	-2.1982
1/18/2021	0.11	-2.2073
1/19/2021	0.113	-2.1804
1/20/2021	0.113	-2.1804
1/21/2021	0.114	-2.1716
1/22/2021	0.112	-2.1893
1/23/2021	0.114	-2.1716
1/24/2021	0.114	-2.1716
1/25/2021	0.113	-2.1804
1/26/2021	0.11	-2.2073
1/27/2021	0.11	-2.2073
1/28/2021	0.114	-2.1716
1/29/2021	0.117	-2.1456
1/30/2021	0.116	-2.1542
1/31/2021	0.113	-2.1804

West Stack NO_X Emissions		
Date	**NO_X (lb/MMBtu)**	**Ln of Raw Data**
2/1/2021	0.112	-2.1893
2/2/2021	0.112	-2.1893
2/3/2021	0.114	-2.1716
2/4/2021	0.116	-2.1542
2/5/2021	0.112	-2.1893
2/6/2021	0.115	-2.1628
2/7/2021	0.112	-2.1893
2/8/2021	0.116	-2.1542
2/9/2021	0.111	-2.1982
2/10/2021	0.111	-2.1982
2/11/2021	0.111	-2.1982
2/12/2021	0.112	-2.1893
2/13/2021	0.113	-2.1804
2/14/2021	0.113	-2.1804
2/15/2021	0.111	-2.1982
2/16/2021	0.109	-2.2164
2/17/2021	0.114	-2.1716
2/18/2021	0.111	-2.1982
2/19/2021	0.11	-2.2073
2/20/2021	0.115	-2.1628
2/21/2021	0.114	-2.1716
2/22/2021	0.11	-2.2073
2/23/2021	0.109	-2.2164
2/24/2021	0.111	-2.1982
2/25/2021	0.113	-2.1804
2/26/2021	0.114	-2.1716
2/27/2021	0.106	-2.2443
2/28/2021	0.102	-2.2828

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
3/1/2021	0.109	-2.2164
3/2/2021	0.117	-2.1456
3/3/2021	0.115	-2.1628
3/4/2021	0.113	-2.1804
3/5/2021	0.116	-2.1542
3/6/2021	0.117	-2.1456
3/7/2021	0.118	-2.1371
3/8/2021	0.114	-2.1716
3/9/2021	0.115	-2.1628
3/10/2021	0.112	-2.1893
3/11/2021	0.113	-2.1804
3/12/2021	0.109	-2.2164
3/13/2021	0.112	-2.1893
3/14/2021	0.115	-2.1628
3/15/2021	0.115	-2.1628
3/16/2021	0.112	-2.1893
3/17/2021	0.109	-2.2164
3/18/2021	0.106	-2.2443
3/19/2021	0.113	-2.1804
3/20/2021	0.119	-2.1286
3/21/2021	0.115	-2.1628
3/22/2021	0.113	-2.1804
3/23/2021	0.107	-2.2349
3/24/2021	0.099	-2.3126
3/25/2021	0.099	-2.3126
3/26/2021	0.102	-2.2828
3/27/2021	0.107	-2.2349
3/28/2021	0.103	-2.2730
3/29/2021	0.117	-2.1456
3/30/2021	0.112	-2.1893
3/31/2021	0.102	-2.2828

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
4/1/2021	0.113	-2.1804
4/2/2021	0.117	-2.1456
4/3/2021	0.119	-2.1286
4/4/2021	0.116	-2.1542
4/5/2021	0.115	-2.1628
4/6/2021	0.113	-2.1804
4/7/2021	0.108	-2.2256
4/8/2021	0.108	-2.2256
4/9/2021	0.096	-2.3434
4/10/2021	0.093	-2.3752
4/11/2021	0.092	-2.3860
4/12/2021	0.097	-2.3330
4/13/2021	0.107	-2.2349
4/14/2021	0.096	-2.3434
4/15/2021	0.099	-2.3126
4/16/2021	0.103	-2.2730
4/17/2021	0.102	-2.2828
4/18/2021	0.107	-2.2349
4/19/2021	0.094	-2.3645
4/20/2021	0.1	-2.3026
4/21/2021	0.101	-2.2926
4/22/2021	0.112	-2.1893
4/23/2021	0.115	-2.1628
4/24/2021	0.111	-2.1982
4/25/2021	0.107	-2.2349
4/26/2021	0.116	-2.1542
4/27/2021	0.108	-2.2256
4/28/2021	0.103	-2.2730
4/29/2021	0.098	-2.3228
4/30/2021	0.11	-2.2073

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
5/1/2021	0.113	-2.1804
5/2/2021	0.102	-2.2828
5/3/2021	0.094	-2.3645
5/4/2021	0.093	-2.3752
5/5/2021	0.1	-2.3026
5/6/2021	0.113	-2.1804
5/7/2021	0.109	-2.2164
5/8/2021	0.111	-2.1982
5/9/2021	0.11	-2.2073
5/10/2021	0.11	-2.2073
5/11/2021	0.114	-2.1716
5/12/2021	0.114	-2.1716
5/13/2021	0.116	-2.1542
5/14/2021	0.114	-2.1716
5/15/2021	0.113	-2.1804
5/16/2021	0.107	-2.2349
5/17/2021	0.107	-2.2349
5/18/2021	0.108	-2.2256
5/19/2021	0.11	-2.2073
5/20/2021	0.109	-2.2164
5/21/2021	0.114	-2.1716
5/22/2021	0.104	-2.2634
5/23/2021	0.104	-2.2634
5/24/2021	0.101	-2.2926
5/25/2021	0.099	-2.3126
5/26/2021	0.096	-2.3434
5/27/2021	0.093	-2.3752
5/28/2021	0.1	-2.3026
5/29/2021	0.093	-2.3752
5/30/2021	0.095	-2.3539
5/31/2021	0.098	-2.3228

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
6/1/2021	0.094	-2.3645
6/2/2021	0.092	-2.3860
6/3/2021	0.084	-2.4769
6/4/2021	0.093	-2.3752
6/5/2021	0.092	-2.3860
6/6/2021	0.095	-2.3539
6/7/2021	0.085	-2.4651
6/8/2021	0.082	-2.5010
6/9/2021	0.083	-2.4889
6/10/2021	0.084	-2.4769
6/11/2021	0.086	-2.4534
6/12/2021	0.092	-2.3860
6/13/2021	0.09	-2.4079
6/14/2021	0.092	-2.3860
6/15/2021	0.095	-2.3539
6/16/2021	0.103	-2.2730
6/17/2021	0.104	-2.2634
6/18/2021	0.098	-2.3228
6/19/2021	0.091	-2.3969
6/20/2021	0.085	-2.4651
6/21/2021	0.084	-2.4769
6/22/2021	0.09	-2.4079
6/23/2021	0.102	-2.2828
6/24/2021	0.1	-2.3026
6/25/2021	0.094	-2.3645
6/26/2021	0.086	-2.4534
6/27/2021	0.087	-2.4418
6/28/2021	0.086	-2.4534
6/29/2021	0.088	-2.4304
6/30/2021	0.089	-2.4191

West Stack NO_X Emissions Date	NO_X (lb/MMBtu)	Ln of Raw Data
7/1/2021	0.085	-2.4651
7/2/2021	0.091	-2.3969
7/3/2021	0.095	-2.3539
7/4/2021	0.093	-2.3752
7/5/2021	0.09	-2.4079
7/6/2021	0.086	-2.4534
7/7/2021	0.087	-2.4418
7/8/2021	0.086	-2.4534
7/9/2021	0.087	-2.4418
7/10/2021	0.093	-2.3752
7/11/2021	0.087	-2.4418
7/12/2021	0.085	-2.4651
7/13/2021	0.086	-2.4534
7/14/2021	0.087	-2.4418
7/15/2021	0.087	-2.4418
7/16/2021	0.095	-2.3539
7/17/2021	0.088	-2.4304
7/18/2021	0.096	-2.3434
7/19/2021	0.094	-2.3645
7/20/2021	0.093	-2.3752
7/21/2021	0.094	-2.3645
7/22/2021	0.103	-2.2730
7/23/2021	0.102	-2.2828
7/24/2021	0.098	-2.3228
7/25/2021	0.089	-2.4191
7/26/2021	0.09	-2.4079
7/27/2021	0.093	-2.3752
7/28/2021	0.095	-2.3539
7/29/2021	0.091	-2.3969
7/30/2021	0.099	-2.3126
7/31/2021	0.105	-2.2538

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
8/1/2021	0.093	-2.3752
8/2/2021	0.1	-2.3026
8/3/2021	0.098	-2.3228
8/4/2021	0.098	-2.3228
8/5/2021	0.098	-2.3228
8/6/2021	0.096	-2.3434
8/7/2021	0.093	-2.3752
8/8/2021	0.094	-2.3645
8/9/2021	0.086	-2.4534
8/10/2021	0.083	-2.4889
8/11/2021	0.083	-2.4889
8/12/2021	0.083	-2.4889
8/13/2021	0.085	-2.4651
8/14/2021	0.084	-2.4769
8/15/2021	0.089	-2.4191
8/16/2021	0.083	-2.4889
8/17/2021	0.084	-2.4769
8/18/2021	0.08	-2.5257
8/19/2021	0.084	-2.4769
8/20/2021	0.084	-2.4769
8/21/2021	0.084	-2.4769
8/22/2021	0.085	-2.4651
8/23/2021	0.084	-2.4769
8/24/2021	0.085	-2.4651
8/25/2021	0.086	-2.4534
8/26/2021	0.09	-2.4079
8/27/2021	0.089	-2.4191
8/28/2021	0.088	-2.4304
8/29/2021	0.088	-2.4304
8/30/2021	0.088	-2.4304
8/31/2021	0.089	-2.4191

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
9/1/2021	0.088	-2.4304
9/2/2021	0.106	-2.2443
9/3/2021	0.106	-2.2443
9/4/2021	0.102	-2.2828
9/5/2021	0.096	-2.3434
9/6/2021	0.101	-2.2926
9/7/2021	0.103	-2.2730
9/8/2021	0.094	-2.3645
9/9/2021	0.097	-2.3330
9/10/2021	0.102	-2.2828
9/11/2021	0.095	-2.3539
9/12/2021	0.093	-2.3752
9/13/2021	0.091	-2.3969
9/14/2021	0.074	-2.6037
9/15/2021	0.026	-3.6497
9/16/2021	0.027	-3.6119
9/17/2021	0.023	-3.7723
9/18/2021	0.028	-3.5756
9/19/2021	0.047	-3.0576
9/20/2021	0.098	-2.3228
9/21/2021	0.094	-2.3645
9/22/2021	0.088	-2.4304
9/23/2021	0.09	-2.4079
9/24/2021	0.032	-3.4420
9/25/2021	0.058	-2.8473
9/26/2021	0.101	-2.2926
9/27/2021	0.099	-2.3126
9/28/2021	0.095	-2.3539
9/29/2021	0.102	-2.2828
9/30/2021	0.093	-2.3752

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
10/1/2021	0.099	-2.3126
10/2/2021	0.097	-2.3330
10/3/2021	0.092	-2.3860
10/4/2021	0.092	-2.3860
10/5/2021	0.09	-2.4079
10/6/2021	0.091	-2.3969
10/7/2021	0.095	-2.3539
10/8/2021	0.094	-2.3645
10/9/2021	0.095	-2.3539
10/10/2021	0.092	-2.3860
10/11/2021	0.094	-2.3645
10/12/2021	0.093	-2.3752
10/13/2021	0.092	-2.3860
10/14/2021	0.094	-2.3645
10/15/2021	0.092	-2.3860
10/16/2021	0.095	-2.3539
10/17/2021	0.105	-2.2538
10/18/2021	0.105	-2.2538
10/19/2021	0.106	-2.2443
10/20/2021	0.103	-2.2730
10/21/2021	0.101	-2.2926
10/22/2021	0.102	-2.2828
10/23/2021	0.099	-2.3126
10/24/2021	0.101	-2.2926
10/25/2021	0.098	-2.3228
10/26/2021	0.101	-2.2926
10/27/2021	0.102	-2.2828
10/28/2021	0.09	-2.4079
10/29/2021	0.093	-2.3752
10/30/2021	0.099	-2.3126
10/31/2021	0.097	-2.3330

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
11/1/2021	0.099	-2.3126
11/2/2021	0.101	-2.2926
11/3/2021	0.103	-2.2730
11/4/2021	0.103	-2.2730
11/5/2021	0.109	-2.2164
11/6/2021	0.105	-2.2538
11/7/2021	0.106	-2.2443
11/8/2021	0.11	-2.2073
11/9/2021	0.1	-2.3026
11/10/2021	0.102	-2.2828
11/11/2021	0.098	-2.3228
11/12/2021	0.099	-2.3126
11/13/2021	0.105	-2.2538
11/14/2021	0.106	-2.2443
11/15/2021	0.112	-2.1893
11/16/2021	0.108	-2.2256
11/17/2021	0.108	-2.2256
11/18/2021	0.122	-2.1037
11/19/2021	0.112	-2.1893
11/20/2021	0.112	-2.1893
11/21/2021	0.107	-2.2349
11/22/2021	0.107	-2.2349
11/23/2021	0.114	-2.1716
11/24/2021	0.107	-2.2349
11/25/2021	0.106	-2.2443
11/26/2021	0.109	-2.2164
11/27/2021	0.111	-2.1982
11/28/2021	0.11	-2.2073
11/29/2021	0.114	-2.1716
11/30/2021	0.113	-2.1804

West Stack NO_X Emissions		
Date	NO_X (lb/MMBtu)	Ln of Raw Data
12/1/2021	0.110	-2.2073
12/2/2021	0.106	-2.2443
12/3/2021	0.110	-2.2073
12/4/2021	0.109	-2.2164
12/5/2021	0.111	-2.1982
12/6/2021	0.107	-2.2349
12/7/2021	0.116	-2.1542
12/8/2021	0.114	-2.1716
12/9/2021	0.112	-2.1893
12/10/2021	0.107	-2.2349
12/11/2021	0.101	-2.2926
12/12/2021	0.112	-2.1893
12/13/2021	0.110	-2.2073
12/14/2021	0.107	-2.2349
12/15/2021	0.106	-2.2443
12/16/2021	0.105	-2.2538
12/17/2021	0.108	-2.2256
12/18/2021	0.109	-2.2164
12/19/2021	0.111	-2.1982
12/20/2021	0.114	-2.1716
12/21/2021	0.111	-2.1982
12/22/2021	0.111	-2.1982
12/23/2021	0.115	-2.1628
12/24/2021	0.112	-2.1893
12/25/2021	0.104	-2.2634
12/26/2021	0.106	-2.2443
12/27/2021	0.109	-2.2164
12/28/2021	0.107	-2.2349
12/29/2021	0.102	-2.2828
12/30/2021	0.099	-2.3126
12/31/2021	0.100	-2.3026

Testing Normality	Raw Data	Logtransformed Data		
Sample Size	1091.00	1091.00		
Kurtosis	4.94	10.59		
SE Kurtosis	0.15	0.15		
Result Kurtosis	non normal	non normal		
Skewness	-2.12	-3.21		
SE Skewness	0.07	0.07	Result Raw Data	Result Log Data
Result Skewness	non normal	non normal	non normal	non normal

Average of Raw Data	9.91E-02
Variance of Raw Data	4.41E-04

2. Calculate sample size, n= 1091

3. Calculate $$\hat{\mu} = \frac{\sum_{i=1}^{n} x_i}{n}$$ -2.35E+00

4. Calculate $$\hat{\sigma}^2 = \frac{\sum_{i=1}^{n} (x_i - \overline{x})^2}{n-1}$$ 0.108421516

5. m= number future runs = 1

6. Calculate $$\beta_{2z} = \frac{e^{4\hat{\sigma}^2} + 2e^{3\hat{\sigma}^2} + 3e^{2\hat{\sigma}^2} - 3}{m\left(e^{\hat{\sigma}^2} - 1\right)^2} + 3\left(1 - \frac{1}{m}\right)$$

a- Numerator first term $e^{4\hat{\sigma}^2} + 2e^{3\hat{\sigma}^2} + 3e^{2\hat{\sigma}^2} - 3$ 5.038175402

b- denominator first term $m\left(e^{\hat{\sigma}^2} - 1\right)^2$ 0.013114242

β_{2z} 384.1758629

7. Calculate $$\sqrt{\beta_{1z}} = \frac{\sqrt{e^{\hat{\sigma}^2} - 1}\left(e^{\hat{\sigma}^2} + 2\right)}{\sqrt{m}}$$ 1.05396592

8. Go to tab distribution for 99 percentile "*z-stat*"

9. substitue the values of β_{2z} $\sqrt{\beta_{1z}}$ in cell D7 and F7 respectively

10. In column AE indentify the value that is the smallest value that is larger than 0.99, note what row number this is.

11. In column B, go down the the row number from Step 10. above, and copy the z value. 3.484 z value from "*z-stat*"

12. calculate the UPL using the formula

$$UPL = e^{\hat{\mu}+\frac{\hat{\sigma}^2}{2}} + \frac{z_{.99}}{m}\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}(e^{\hat{\sigma}^2}-1) + m^2e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n}+\frac{\hat{\sigma}^4}{2(n-1)}\right)}$$

a- Calculate	$e^{\hat{\mu}+\frac{\hat{\sigma}^2}{2}}$	0.100612465
b- Calculate	$e^{2\hat{\mu}+\hat{\sigma}^2}$	0.010122868
c- Calculate	$(e^{\hat{\sigma}^2}-1)$	0.114517433
d-calculate	$\left(\frac{\hat{\sigma}^2}{n}+\frac{\hat{\sigma}^4}{2(n-1)}\right)$	0.00010477
e- Calculate	$\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}(e^{\hat{\sigma}^2}-1) + m^2e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n}+\frac{\hat{\sigma}^4}{2(n-1)}\right)}$	0.034063
f- Calculate UPL		0.219

Δz	z	β_{2z}	$\sqrt{\beta_{1z}}$	$\left(1-\frac{\sqrt{\beta_{1z}}}{6}\left(3z-z^3\right)+\frac{\left(\beta_{2z}-3\right)\left(3-6z^2+z^4\right)}{24}\right)$	Normal distribution $\phi(z)$	distribution of Z $f_G(z)=\left(1-\frac{\sqrt{\beta_{1z}}}{6}\left(3z-z^3\right)+\frac{\left(\beta_{2z}-3\right)\left(3-6z^2+z^4\right)}{24}\right)\phi(z)$	Absolute values	$\frac{\Delta x}{2}\left(f(a)+2\sum_{i=1}^{M}f(x_i)+f(b)\right)$	Cumulative	normalization
0.101		384.1759	1.053966							
	-5 =f(a)			7573.43	1.48672E-06	0.011259566	0.011259566	0.000568608	0.000568608	1.27647E-05
1	-4.899			6891.875	2.45094E-06	0.016891569	0.016891569	0.001706049	0.002274657	5.10639E-05
2	-4.798			6254.987	3.9995E-06	0.025016836	0.025016836	0.0025267	0.004801357	0.000107786
3	-4.697			5660.863	6.46025E-06	0.036570572	0.036570572	0.003693628	0.008494985	0.000190705
4	-4.596			5107.64	1.03291E-05	0.052757267	0.052757267	0.005328484	0.013823469	0.000310324
5	-4.495			4593.495	1.63472E-05	0.075090993	0.075090993	0.00758419	0.021407659	0.000480582
6	-4.394			4116.642	2.56093E-05	0.105424163	0.105424163	0.01064784	0.032055499	0.000719616
7	-4.293			3675.339	3.97118E-05	0.145954186	0.145954186	0.014741373	0.046796872	0.001050546
8	-4.192			3267.879	6.09553E-05	0.199194386	0.199194386	0.020118633	0.066915505	0.001502191
9	-4.091			2892.598	9.26132E-05	0.267892746	0.267892746	0.027057167	0.093972673	0.002109599
10	-3.99			2547.871	0.000139285	0.354880196	0.354880196	0.0358429	0.129815572	0.002914239
11	-3.889			2232.112	0.000207351	0.462830004	0.462830004	0.04674583	0.176561403	0.003963639
12	-3.788			1943.775	0.000305546	0.593912444	0.593912444	0.059985157	0.23654656	0.005310251
13	-3.687			1681.353	0.000445674	0.749335136	0.749335136	0.075682849	0.312229408	0.00700926
14	-3.586			1443.38	0.000643469	0.928770299	0.928770299	0.0938058	0.406035209	0.009115113
15	-3.485			1228.428	0.000919619	1.129686014	1.129686014	0.114098287	0.520133496	0.011676514
16	-3.384			1035.111	0.001300942	1.346619439	1.346619439	0.136008563	0.656142059	0.01472978
17	-3.283			862.0801	0.001821704	1.570454681	1.570454681	0.158615923	0.814757982	0.01829056
18	-3.182			708.0278	0.002525035	1.787794595	1.787794595	0.180567254	0.995325236	0.022344127
19	-3.081			571.6855	0.003464389	1.980540796	1.980540796	0.20003462	1.195359857	0.026834718
20	-2.98			451.8245	0.004704958	2.125815006	2.125815006	0.214707316	1.410067172	0.031654698
21	-2.879			347.2557	0.006324913	2.196362236	2.196362236	0.221832586	1.631899758	0.036634634
22	-2.778			256.8298	0.008416337	2.161566436	2.161566436	0.21831821	1.850217968	0.041535675
23	-2.677			179.437	0.011085658	1.989177375	1.989177375	0.200906915	2.051124883	0.046045848
24	-2.576			114.0072	0.014453386	1.647790329	1.647790329	0.166426823	2.217551706	0.049781976
25	-2.475			59.51004	0.018652949	1.11003767	1.11003767	0.112113805	2.329665511	0.052298827
26	-2.374			14.95473	0.023828414	0.356347523	0.356347523	0.0359911	2.365656611	0.053106793
27	-2.273			-20.6098	0.030130931	-0.620991902	0.620991902	0.062720182	2.428376793	0.054514803
28	-2.172			-48.0949	0.03771375	-1.813839526	1.813839526	0.183197792	2.611574585	0.058627423
29	-2.071			-68.3724	0.046725789	-3.194754887	3.194754887	0.322670244	2.934244829	0.065871071
30	-1.97			-82.2744	0.057303789	-4.714632449	4.714632449	0.476177877	3.410422706	0.076560822
31	-1.869			-90.5932	0.069563239	-6.3019543	6.3019543	0.636497384	4.04692009	0.090849597
32	-1.768			-94.0816	0.083588399	-7.864130245	7.864130245	0.794277155	4.841197245	0.108680381
33	-1.667			-93.4527	0.099421884	-9.291246469	9.291246469	0.938415893	5.779613138	0.129746946
34	-1.566			-89.38	0.117054396	-10.46232016	10.46232016	1.056694336	6.836307475	0.153468752
35	-1.465			-82.4971	0.136415346	-11.2538731	11.2538731	1.136641183	7.972948658	0.178985291
36	-1.364			-73.3982	0.157365126	-11.55032056	11.55032056	1.166582377	9.139531034	0.205173981
37	-1.263			-62.6377	0.179689839	-11.25536185	11.25536185	1.136791547	10.27632258	0.230693896
38	-1.162			-50.7304	0.203099244	-10.30330005	10.30330005	1.040633305	11.31695589	0.254055147
39	-1.061			-38.1513	0.227228529	-8.66905697	8.66905697	0.875574754	12.19253064	0.273710986
40	-0.96			-25.3358	0.251644341	-6.375622167	6.375622167	0.643937839	12.83646848	0.288166793
41	-0.859			-12.6799	0.275855243	-3.497806242	3.497806242	0.35327843	13.18974691	0.296097565
42	-0.758			-0.53942	0.299326439	-0.161461403	0.161461403	0.016307602	13.20605451	0.296463656
43	-0.657			10.76906	0.321498297	3.462233897	3.462233897	0.349685624	13.55574013	0.304313773
44	-0.556			20.96879	0.341807853	7.167298167	7.167298167	0.723897115	14.27963725	0.320564591
45	-0.455			29.82269	0.359712192	10.72758393	10.72758393	1.083485977	15.36312323	0.344887845
46	-0.354			37.1333	0.37471238	13.91430769	13.91430769	1.405345077	16.7684683	0.376436536
47	-0.253			42.74287	0.386376486	16.51483824	16.51483824	1.667998663	18.43646697	0.413881556
48	-0.152			46.53327	0.394360216	18.3508718	18.3508718	1.853438052	20.28990502	0.455489519
49	-0.051			48.42608	0.398423793	19.29410389	19.29410389	1.948704493	22.23860951	0.499236125
50	0.05			48.38252	0.398443914	19.27772065	19.27772065	1.947049786	24.1856593	0.542945583
51	0.151			46.40347	0.394419966	18.30245606	18.30245606	1.848548062	26.03420736	0.58444377
52	0.252			42.5295	0.386474058	16.43654685	16.43654685	1.660091232	27.69429859	0.621711276
53	0.353			36.84081	0.374844865	13.80958851	13.80958851	1.394768439	29.08906703	0.653022532
54	0.454			29.4573	0.359875719	10.60096738	10.60096738	1.070697706	30.15976474	0.677058701
55	0.555			20.53852	0.34199778	7.024127964	7.024127964	0.709436924	30.86920166	0.692984901
56	0.656			10.28368	0.32170943	3.308357054	3.308357054	0.334144062	31.20334572	0.700486124
57	0.757			-1.06833	0.299553264	-0.320022626	0.320022626	0.032322285	31.23566801	0.70121173
58	0.858			-13.239	0.276092166	-3.655177311	3.655177311	0.369172908	31.60484092	0.709499319
59	0.959			-25.91	0.25188591	-6.526372391	6.526372391	0.659163612	32.26400453	0.724296929
60	1.06			-38.7236	0.227469632	-8.808450162	8.808450162	0.889653466	33.15365799	0.744268823
61	1.161			-51.2822	0.203335281	-10.42748566	10.42748566	1.053176052	34.20683405	0.767911647
62	1.262			-63.1486	0.17991684	-11.36149795	11.36149795	1.147511293	35.35434534	0.79367221
63	1.363			-73.8459	0.157579839	-11.63662585	11.63662585	1.175299211	36.52964455	0.820056585
64	1.464			-82.8576	0.136615273	-11.31961075	11.31961075	1.143280686	37.67292523	0.845722174
65	1.565			-89.6274	0.117237788	-10.5077211	10.5077211	1.061279831	38.73420507	0.869546921
66	1.666			-93.5596	0.099587708	-9.317383713	9.317383713	0.941055755	39.67526082	0.890672748
67	1.767			-94.0185	0.083736272	-7.872758245	7.872758245	0.795148583	40.4704094	0.908523095
68	1.868			-90.329	0.069693339	-6.295328349	6.295328349	0.635828163	41.10623757	0.922796847
69	1.969			-81.7762	0.05741676	-4.695322906	4.695322906	0.474227613	41.58046518	0.933442816
70	2.07			-67.6055	0.046822635	-3.16546944	3.16546944	0.319712413	41.90017759	0.940620063
71	2.171			-47.0229	0.037795734	-1.777264272	1.777264272	0.179503692	42.07968129	0.944649754
72	2.272			-19.1943	0.030199481	-0.579659059	0.579659059	0.058545565	42.13822685	0.945964048
73	2.373			16.75361	0.023885038	0.400160695	0.400160695	0.04041623	42.17864308	0.946871354
74	2.474			61.73417	0.018699163	1.154377228	1.154377228	0.1165921	42.29523518	0.949488739
75	2.575			116.7002	0.014490659	1.691062521	1.691062521	0.170797315	42.4660325	0.95332298
76	2.676			182.6442	0.011115369	2.030157378	2.030157378	0.205045895	42.67107839	0.95792607
77	2.777			260.5983	0.008439746	2.19938383	2.19938383	0.222137767	42.89321616	0.962912856
78	2.878			351.6345	0.006343145	2.230468844	2.230468844	0.225277353	43.11849351	0.967970124
79	2.979			456.8642	0.004718997	2.155940932	2.155940932	0.217750034	43.33624354	0.972858409
80	3.08			577.4387	0.003475077	2.00664414	2.00664414	0.202671058	43.5389146	0.977408186

Δz	z	β_{2z}	$\sqrt{\beta_{1z}}$	$\left(1-\frac{\sqrt{\beta_{1z}}}{6}\left(3z-z^3\right)+\frac{\left(\beta_{2z}-3\right)\left(3-6z^2+z^4\right)}{24}\right)$	Normal distribution $\phi(z)$	distribution of Z $f_G(z)=\left(1-\frac{\sqrt{\beta_{1z}}}{6}\left(3z-z^3\right)+\frac{\left(\beta_{2z}-3\right)\left(3-6z^2+z^4\right)}{24}\right)\phi(z)$	Absolute values	$\frac{\Delta x}{2}\left(f(a)+2\sum_{i=1}^{M}f(x_i)+f(b)\right)$	Cumulative	normalization
0.101		384.1759	1.053966							
	-5 =f(a)			7573.43	1.48672E-06	0.011259566	0.011259566	0.000568608	0.000568608	1.27647E-05
81	3.181			714.5487	0.002533081	1.810009587	1.810009587	0.182810968	43.72172557	0.981512123
82	3.282			869.4248	0.001827693	1.589042028	1.589042028	0.160493245	43.88221882	0.985115047
83	3.383			1043.337	0.001305351	1.36192163	1.36192163	0.137554085	44.0197729	0.988203009
84	3.484			1237.596	0.000922829	1.142089271	1.142089271	0.115351016	44.13512392	0.990792532
85	3.585			1453.55	0.00064578	0.938673982	0.938673982	0.094806072	44.22992999	0.99292084
86	3.686			1692.589	0.00044732	0.757128627	0.757128627	0.076469991	44.30639998	0.99463752
87	3.787			1956.141	0.000306705	0.59995899	0.59995899	0.060595858	44.36699584	0.995997841
88	3.888			2245.676	0.000208159	0.467456634	0.467456634	0.04721312	44.41420896	0.997057732
89	3.989			2562.701	0.000139842	0.358372618	0.358372618	0.036195634	44.45040459	0.99787029
90	4.09			2908.764	9.29928E-05	0.270494104	0.270494104	0.027319905	44.4777245	0.998483596
91	4.191			3285.453	6.12113E-05	0.201106785	0.201106785	0.020311785	44.49803628	0.998939577
92	4.292			3694.395	3.98826E-05	0.147342042	0.147342042	0.014881546	44.51291783	0.999273654
93	4.393			4137.256	2.5722E-05	0.106418586	0.106418586	0.010748277	44.52366611	0.999514943
94	4.494			4615.743	1.64209E-05	0.075794591	0.075794591	0.007655254	44.53132136	0.999686796
95	4.595			5131.603	1.03767E-05	0.053248925	0.053248925	0.005378141	44.5366995	0.999807531
96	4.696			5686.621	6.49066E-06	0.036909916	0.036909916	0.003727901	44.5404274	0.999891218
97	4.797			6282.622	4.01874E-06	0.025248203	0.025248203	0.002550069	44.54297747	0.999948465
98	4.898			6921.473	2.46298E-06	0.017047415	0.017047415	0.001721789	44.54469926	0.999987118
99	4.999			7605.077	1.49417E-06	0.011363285	0.011363285	0.000573846	44.54527311	1

APPENDIX D. SCR AND SNCR COST ANALYSIS

As discussed in Section 2, SCR and SNCR are not technically feasible for CPP's boilers due to low exhaust temperatures. However, in anticipation of questions from DOEE, CPP has evaluated cost efficiency of SCR and SNCR and details are provided in this appendix which show that SCR and SNCR are also not cost effective. Due to space restrictions and routing of the existing exhaust stacks, the only way to install SNCR or SCR technology on Boilers 3 through 7 would be to install an SCR/SNCR on Boiler 3, a single SCR/SNCR controlling emissions from Boilers 4 and 5, and a separate single SCR/SNCR controlling emissions from Boilers 6 and 7.

SCR cost analyses in this appendix were calculated based on EPA's *SCR Cost Calculation Spreadsheet*.[10] SNCR cost analyses were calculated based on EPA's *Air Pollution Control Cost Estimation Spreadsheets for Selective Non-Catalytic Reduction (SNCR)*.[11] Note that these spreadsheets do not account for the AOC-specific cost contingency factors utilized in the cost analyses in Appendix A. This, combined with the conservative control efficiencies that likely could not be achieved due to exhaust temperature, causes the cost effectiveness values to be conservative.

This appendix contains detailed cost efficiency calculations for:

- Installing SCR on Boiler 3
- Installing SNCR on Boiler 3
- Installing SCR on the combined exhaust of Boilers 4 and 5
- Installing SNCR on the combined exhaust of Boilers 4 and 5
- Installing SCR on the combined exhaust of Boilers 6 and 7
- Installing SNCR on the combined exhaust of Boilers 6 and 7

10 https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

11 https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution (updated 3/19/2021).

Boiler 3 (EU-3)
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 Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	203	MMBtu/hour	
Baseline NO_X Emissions =	Average of 2020-2021 observed emissions	13.34	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	245,380	MMBtu/year	
Controlled NO_X Emissions Rate =		0.012	lb/MMBtu	
Controlled NO_X Emissions =		1.47	tons/year	
Total NO_x removed per year =	** See Footnote	11.87	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.10		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	59,679	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	74.92	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3211	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	796.53	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	62	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	5	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	71	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	58	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	7	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	25	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,200	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0720

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	104.38	kW

Boiler 3 (EU-3)
SCR 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:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

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

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$5,629,948	in 2021 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$72,675	in 2021 dollars
Indirect Annual Costs (IDAC) =	$408,322	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$480,997	in 2021 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$28,150	in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$3,415	in 2021 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$16,655	in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$24,455	in 2021 dollars
Direct Annual Cost =		$72,675	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,966	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$405,356	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$408,322	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$480,997	per year in 2021 dollars
NOx Removed =	12	tons/year
Cost Effectiveness =	$40,531	per ton of NOx removed in 2021 dollars

Boiler 3 (EU-3)
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 Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	203	MMBtu/hour	
Baseline NO_X Emissions =	Average of 2020-2021 observed emissions	13.34	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	245,380	MMBtu/year	
Controlled NO_X Emissions Rate =		0.060	lb/MMBtu	
Controlled NO_X Emissions =		7.36	tons/year	
Total NO_x removed per year =	** See Footnote	5.98	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 25 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	28	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	3.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	1,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0720

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47$ x NOx_{in} x NSR x $Q_B)/NPHR$ =	1.2	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	6	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.07	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel$ x %Ash x $1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Boiler 3 (EU-3)
SNCR 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 ($SNCR_{cost}$) =	$659,894	in 2021 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2021 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,007,774	in 2021 dollars
Total Capital Investment (TCI) =	$2,167,968	in 2021 dollars

#VALUE!

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 ($SNCR_{cost}$) =	$659,894	in 2021 dollars

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 2021 dollars

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,007,774	in 2021 dollars

Boiler 3 (EU-3)
SNCR Cost Estimate
Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$36,750	in 2021 dollars
Indirect Annual Costs (IDAC) =	$157,069	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$193,819	in 2021 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$32,520	in 2021 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$3,869	in 2021 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$102	in 2021 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$32	in 2021 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$227	in 2021 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2021 dollars
Direct Annual Cost =		$36,750	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$976	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$156,094	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$157,069	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$193,819	per year in 2021 dollars
NOx Removed =	6	tons/year
Cost Effectiveness =	$32,421	per ton of NOx removed in 2021 dollars

Boiler 4,5 (EU-4,5)
SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Baseline NO_x Emissions =	Average of 2020-2021 observed emissions	9.04	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	172,660	MMBtu/year	
Controlled NO_X Emissions Rate =		0.012	lb/MMBtu	
Controlled NO_X Emissions =		1.04	tons/year	
Total NO_x removed per year =	** See Footnote	8.01	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.10		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	52,350	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	111.18	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3211	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	470.85	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	55	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst}))$ + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	63	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	7.9	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to

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	0.0720

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	61.70	kW

Boiler 4,5 (EU-4,5)
SCR 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:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

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

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,000,366	in 2021 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$48,580	in 2021 dollars
Indirect Annual Costs (IDAC) =	$290,894	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$339,475	in 2021 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$20,002	in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,403	in 2021 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$11,719	in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$14,456	in 2021 dollars
Direct Annual Cost =		$48,580	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$288,026	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$290,894	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$339,475	per year in 2021 dollars
NOx Removed =	8	tons/year
Cost Effectiveness =	$42,403	per ton of NOx removed in 2021 dollars

Boiler 4,5 (EU-4,5)
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 Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Baseline NO_X Emissions =	Average of 2020-2021 observed emissions	9.04	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	172,660	MMBtu/year	
Controlled NO_X Emissions Rate =		0.060	lb/MMBtu	
Controlled NO_X Emissions =		5.18	tons/year	
Total NO_x removed per year =	** See Footnote	3.86	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 25 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	2.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0720

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	0.7	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	4	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.04	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Boiler 4,5 (EU-4,5)
SNCR 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 ($SNCR_{cost}$) =	$529,153	in 2021 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2021 dollars
Balance of Plant Costs (BOP_{cost}) =	$795,466	in 2021 dollars
Total Capital Investment (TCI) =	$1,722,005	in 2021 dollars

#VALUE!

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 ($SNCR_{cost}$) =	$529,153	in 2021 dollars

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 2021 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$795,466	in 2021 dollars

Boiler 4,5 (EU-4,5)
SNCR Cost Estimate
Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$28,806	in 2021 dollars
Indirect Annual Costs (IDAC) =	$124,759	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$153,566	in 2021 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$25,830	in 2021 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$2,722	in 2021 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$72	in 2021 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$22	in 2021 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$160	in 2021 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2021 dollars
Direct Annual Cost =		$28,806	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$775	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$123,984	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$124,759	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$153,566	per year in 2021 dollars
NOx Removed =	4	tons/year
Cost Effectiveness =	$39,763	per ton of NOx removed in 2021 dollars

Boiler 6,7 (EU-6,7)
SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Baseline NO_x Emissions =	Average of 2020-2021 observed emissions	8.20	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	159,266	MMBtu/year	
Controlled NO_X Emissions Rate =		0.012	lb/MMBtu	
Controlled NO_X Emissions =		0.96	tons/year	
Total NO_x removed per year =	** See Footnote	7.25	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.10		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	52,350	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	111.18	/hour	
Residence Time	1/V_{space}	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3211	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	470.85	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	55	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	63	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	7.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	15	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	700	gallons (storage needed to store a 14 day reagent supply rounded to

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	0.0720

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	61.70	kW

Boiler 6,7 (EU-6,7)
SCR 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:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

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

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

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

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

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

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$4,000,366	in 2021 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$47,485	in 2021 dollars
Indirect Annual Costs (IDAC) =	$290,894	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$338,379	in 2021 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$20,002	in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,217	in 2021 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$10,810	in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$14,456	in 2021 dollars
Direct Annual Cost =		$47,485	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,868	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$288,026	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$290,894	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$338,379	per year in 2021 dollars
NOx Removed =	7	tons/year
Cost Effectiveness =	$46,698	per ton of NOx removed in 2021 dollars

Boiler 6,7 (EU-6,7)
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 Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Baseline NO_X Emissions =	Average of 2020-2021 observed emissions	8.20	tons/year	
Unit Heat Input Rate =	Average of 2020-2021 heat input	159,266	MMBtu/year	
Controlled NO_X Emissions Rate =		0.060	lb/MMBtu	
Controlled NO_X Emissions =		4.78	tons/year	
Total NO_x removed per year =	** See Footnote	3.42	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 25 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

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

** Formula for NOx removed was overwritten to be consistent with methodology for LNB and PGR calculations.

Reagent Data:

Type of reagent used: Ammonia

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

Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x NSR x $MW_R)/(MW_{NOx}$ x SR) = (whre SR = 1 for NH_3; 2 for Urea)	5	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	16	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	2.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0720

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	0.7	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	4	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.04	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Boiler 6,7 (EU-6,7)
SNCR 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 ($SNCR_{cost}$) =	$529,153	in 2021 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2021 dollars
Balance of Plant Costs (BOP_{cost}) =	$795,466	in 2021 dollars
Total Capital Investment (TCI) =	$1,722,005	in 2021 dollars

#VALUE!

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 ($SNCR_{cost}$) =	$529,153	in 2021 dollars

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 2021 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$795,466	in 2021 dollars

Boiler 6,7 (EU-6,7)
SNCR Cost Estimate
Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$28,576	in 2021 dollars
Indirect Annual Costs (IDAC) =	$124,759	in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	$153,335	in 2021 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$25,830	in 2021 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$2,511	in 2021 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$66	in 2021 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$21	in 2021 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$147	in 2021 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2021 dollars
Direct Annual Cost =		$28,576	in 2021 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$775	in 2021 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$123,984	in 2021 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$124,759	in 2021 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$153,335	per year in 2021 dollars
NOx Removed =	3	tons/year
Cost Effectiveness =	$44,787	per ton of NOx removed in 2021 dollars

APPENDIX E. QUOTE FOR BURNER REPLACEMENTS

RACT PROJECT COSTS - BOILER NOS. 3 - 7 - 29 Jan22

AOC 2022 CPP RACT ANALYSIS

	BOILER NO. 3		BOILER NO. 4		BOILER NOS. 4 - 7	
	LNB ($)	LNB & FGR ($)	LNB ($)	LNB & FGR ($)	LNB ($)	LNB & FGR ($)
EQUIPMENT						
1. BURNER	1,050,000	1,100,000	200,000	225,000	800,000	900,000
2. FGR FAN	---	150,000	---	25,000	---	100,000
SUBTOTAL	1,050,000	1,250,000	200,000	250,000	800,000	1,000,000
DIRECT INSTALLATION						
1. BURNER INSTALLATION	80,000	80,000	20,000	20,000	80,000	80,000
2. FRONT WALL MODIFICATIONS	60,000	60,000	30,000	30,000	120,000	120,000
3. GAS PIPING	20,000	20,000	10,000	10,000	40,000	40,000
4. OIL PIPING	20,000	20,000	10,000	10,000	40,000	40,000
5. BREACHING	---	100,000	---	50,000	---	200,000
6. CONTROL DAMPER	---	20,000	---	15,000	---	60,000
7. CONTROL WIRING	40,000	50,000	20,000	25,000	80,000	100,000
8. CONTROL/ BMS INCORPORATION	60,000	60,000	30,000	30,000	120,000	120,000
9. ELECTRICAL	20,000	50,000	10,000	25,000	40,000	100,000
SUBTOTAL	300,000	460,000	130,000	215,000	520,000	860,000
INDIRECT INSTALLATION COSTS						
1. ENGINEERING (10%)	135,000	171,000	33,000	46,500	132,000	186,000
2. CONSTRUCTION ADMIN (4%)	54,000	68,400	13,200	18,600	52,800	74,400
3. CONTRACTOR FEES (10%)	135,000	171,000	33,000	46,500	132,000	186,000
4. START-UP (2%)	27,000	34,200	6,600	9,300	26,400	37,200
5. CONTINGENCY (3%)	40,500	51,300	9,900	13,950	39,600	55,800
SUBTOTAL	391,500	495,900	95,700	134,850	382,800	539,400
AOC REQUIRED INDIRECT COSTS						
1. CONTINGENCY (20%)	348,300	441,180	85,140	119,970	340,560	479,880
2. CONSTRUCTION ADMIN (4%)	69,660	88,236	17,028	23,994	68,112	95,976
3. GOVERNMENT TEST AND Q/C (2.5%)	43,538	55,148	10,643	14,996	42,570	59,985
4. AOC CONSTRUCTION MANAGEMENT (20%)	348,300	441,180	85,140	119,970	340,560	479,880
5. AOC PM FEES (5%)	87,075	110,295	21,285	29,993	85,140	119,970
6. OTHER (5%)	87,075	110,295	21,285	29,993	85,140	119,970
SUBTOTAL	983,948	1,246,334	240,521	338,915	962,082	1,355,661
GRAND TOTAL	2,725,448	3,452,234	666,221	938,765	2,664,882	3,755,061