State Implementation Plan Revision – Appendix P

Second Regional Haze Plan (2018 – 2028)

By

Air Quality Program

Washington State Department of Ecology
Olympia, Washington

Appendix P. Refineries' Documents for Plan Development

BP CHERRY POINT REFINERY
REGIONAL HAZE FOUR FACTOR ANALYSIS

Prepared for
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Cherry Point Refinery
Blaine, Washington

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Date
April 2020

Bright ideas. Sustainable change.

CONTENTS

Attachments

1. BACKGROUND AND SUMMARY INFORMATION

BP North America (BP) owns and operates the Cherry Point Refinery (hereafter, "the Refinery") located in Blaine, Washington.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule). The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.

During the first planning period, BP evaluated 22 applicable emission units at the Refinery through the Regional Haze Rule Best Available Retrofit Technology (BART) analysis. The BP BART analysis involved detailed engineering assessments of technical feasibility of retrofits, detailed "Appraise" and "Select" capital costs evaluations performed by engineering contractors, and a modeling analysis to evaluate visibility improvements from installing new control technologies. BP submitted the results of the BART analysis to Ecology in March 2008. The BART analysis indicated low-NOx burners were considered BART for six of the 22 applicable emission units at the Refinery, and BP confirmed the decommissioning of two BART-applicable emission units (#1 and #3 Boilers) by 2010.[1] Ecology issued BART Determination Order #7836 in July 2010. The BART Determination Order limited Refinery emissions of oxides of nitrogen (NOx), sulfur dioxide (SO_2), and particulate matter (PM) primarily by incorporating emission limits, work practices, and other conditions from existing air permits. Total NOx, SO_2, and PM emissions from the Refinery have decreased significantly over the last decade (35 percent decrease, or 1,400 tons per year decrease, comparing 2018 emissions to 2008 emissions).

Regional Haze SIPs for the second planning period must be submitted to EPA for review by July 31, 2021. On November 27, 2019, the Washington Department of Ecology (Ecology) requested a four-factor analysis (hereafter, "the Analysis") for each fluid catalytic cracking unit (FCCU), boiler with heat input greater than 40 million British thermal units per hour (MMBtu/hr), and heater with heat input greater than 40 MMBtu/hr that has not been retrofitted since 2005. BP requested clarification on several aspects of the Analysis on January 31, 2020. Ecology has since determined the Analysis should include only NOx emissions and evaluations of two control options: Low NOx burner (LNB) and selective catalytic reduction (SCR).[2] In consultation with Ecology, nine emission units at the Refinery were identified as qualifying for the Analysis, including:

- Crude Charge Heater;
- South Vacuum Heater;

[1] Several low NOx burner retrofit projects and the decommissioning of the boilers were executed contemporarily at the BP Cherry Point refinery for NOx reductions required by the 2001 Consent Decree (for BP Exploration & Oil Co., AMOCO, and Atlantic Richfield Company [Civil No. 2:96 CV 095 RL]).

[2] Ecology's March 9, 2020 email from Mr. Chris Hanlon-Meyer to Mr. Bob Poole (Western States Petroleum Association, WSPA)

- #1 Reformer Heaters;
- #2 Reformer Heaters;
- Naphtha HDS Charger Heater;
- Naphtha HDS Stripper Reboiler;
- Hydrocracker R-4 Heater;
- #1 Hydrogen Plant (North and South Furnaces); and
- #5 Boiler.

BP has completed the requested Analysis according to the regulatory factors in 40 CFR 51.308(f)(2) and concluded the following:

- **The cost of compliance** – The average cost-effectiveness of implementing additional NOx controls at the Refinery range from $23,000 to $127,000 per ton NOx removed would not be considered cost-effective in a top-down Best Available Control Technology (BACT) analysis and should therefore be determinative in rejecting additional NOx controls as necessary for reasonable progress;
- **The time necessary for compliance** – Implementation of additional NOx control options will require a minimum of 8 to 10 years based on Refinery turnaround (TAR) planning requirements;
- **The energy and non-air quality environmental impacts of compliance** – The SCR NOx control option results in increased electrical power usage, increased ammonia emissions, increased particulate matter emissions, and additional solid waste disposal compared to current operations; and
- **The remaining useful life of emission units** – The assumed remaining useful life of Refinery emission units for this Analysis is more than 25 years.

Table 1-1 summarizes the Analysis findings for the nine emission units evaluated at the Refinery.

TABLE 1-1. FOUR-FACTOR ANALYSIS SUMMARY

Source	NOx Four-Factor Analysis Finding
Crude Charge Heater	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements
South Vacuum Heater	Existing Ultra Low NOx Burners (ULNBs)
Naphtha HDS Charge Heater	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements
Naphtha HDS Stripper Reboiler	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements

Source	NOx Four-Factor Analysis Finding
#1 Reformer Heaters	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements
#2 Reformer Heater	Existing LNBs
Hydrocracker R-4 Heater	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements
#1 Hydrogen Plant Furnaces	Good Combustion Practices – 40 CFR 63, Subpart DDDDD heater tune-up requirements
# 5 Boiler	Existing ULNBs

2. FOUR FACTOR ANALYSIS PROCESS

BP retained Ramboll US Corporation (Ramboll) to assist with preparation of this Analysis. Ramboll reviewed NOx emission control options requested by Ecology, eliminated technically infeasible control options, and conducted the Analysis for each technically feasible emission reduction option using the four factors listed in 40 CFR 51.308(f)(2)(i): cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. A summary of each step in the Analysis is provided below.

2.1 Cost of Compliance (First Regulatory Factor)

The control technology cost analysis performed for an emissions unit considers the unit's existing emissions performance and the design parameters and effectiveness of each control technology evaluated for the same emissions unit. A capital recovery factor performs the function of annualizing total capital investments over the equipment life. An interest rate of five percent was used to calculate a capital recovery factor based on the past Federal Reserve Prime Rate.[3] EPA's Control Cost Manual recommends using company-specific cost of capital or the Federal Prime Rate for cost-effectiveness evaluations.[4] BP's current cost of capital is higher than five percent, but the cost-effectiveness evaluations included with this Analysis were conservatively based on a five percent interest rate.

The control technology costs can be examined in two different ways: (1) the average cost effectiveness, and (2) the incremental cost effectiveness.

The formula for determining the average cost effectiveness for a particular control technology is the total annualized costs of that control technology divided by the annual emissions reduction achieved by the same control technology, expressed as dollars ($) per ton:

$$Average\ Cost\ Effectiveness\left(\frac{\$}{ton}\right) = \frac{Total\ Annualized\ Costs\ of\ Control\ Options}{(Baseline\ Annual\ Emissions - Control\ Option\ Annual\ Emissions)}$$

Ecology requested BP use the actual NOx emissions for 2016, or another representative year, as the baseline annual emissions for each emission unit. For this Analysis, 2016 annual emissions were used as the baseline for cost-effectiveness calculations.

The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$Incremental\ cost\ effectiveness\left(\frac{\$}{ton}\right) = \frac{Total\ Annualized\ Costs\ of\ Control\ Options - Total\ Annualized\ Cots\ of\ Next\ Control\ Option}{Control\ Option\ Annual\ Emissions - Next\ Control\ Option\ Annual\ Emissions}$$

The incremental cost effectiveness is intended to demonstrate which control technology options provide the most efficient use of resources. Both the average cost effectiveness and the incremental cost effectiveness are considered when making an Analysis determination.

[3] Prime rate information from https://www.federalreserve.gov/releases/h15/.

[4] EPA Cost Control Manual, Section 1, Chapter 2 (Cost Estimation: Concepts and Methodology), November 2017.

2.2 Time Necessary for Compliance (Second Regulatory Factor)

Prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls are identified and documented in the Analysis.

2.3 Energy and Non-Air Quality Environmental Impacts of Compliance (Third Regulatory Factor)

The energy impacts, whether energy penalties or benefits, should be evaluated for each control technology option. In general, only direct energy consumption and not indirect energy impacts should be considered. Issues such as the use of locally scarce fuels or whether a given alternative would result in significant economic disruption or unemployment can also be considered in the energy impact analysis. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, energy impacts are also to be factored into the control technology cost analysis.

An analysis of any environmental impacts other than air quality can be used to evaluate control technology options. Non-air quality impacts can include, but are not limited to, solid or hazardous waste generation, wastewater generation, irreversible or irretrievable commitment of resources (e.g., use of scarce water resources), noise levels, radiant heat, or dissipated electrical energy.

Although control technologies are used to reduce emissions of a specific pollutant, in some cases, the emissions of other pollutants may increase, or a new pollutant may be introduced. Collateral emissions increases associated with technically feasible control technology options are included in the Analysis.

2.4 Remaining Useful Life of Emissions Unit (Fourth Regulatory Factor)

The "remaining useful life"[5] of an emissions unit is accounted for in the Analysis. More specifically, as part of the annualized cost determination for a particular control technology option, a time period must be assigned for amortization of the control technology equipment. If the remaining useful life of the relevant emissions unit will clearly exceed this time period, then the unit's remaining useful life has essentially no effect on the Analysis determination process. However, if the remaining useful life of the relevant emissions unit is less than the time period that would typically be used for amortizing costs for the particular control technology, then the shorter time period can be used in the control technology amortization calculation. If the use of this shorter time period affects the outcome of the Analysis determination for the emissions unit, then the projected date for the unit to permanently stop operations should be assured by a federally enforceable restriction preventing further operation after such date.

[5] "For purposes of these guidelines, the remaining useful life is the difference between: (1) The date that controls will be put in place […]; you are conducting the Four-Factor Analysis; and (2) The date the facility permanently stops operations." (40 CFR Part 51, Appendix Y).

3. FOUR-FACTOR ANALYSIS DETERMINATION

3.1 NO_X Emissions from Heaters and Boilers

BP used three steps to identify potential retrofit NOx control options, eliminate technically infeasible control options, and evaluate the effectiveness of technically feasible control options. The fourth step is summarizing the Analysis results. A summary of each step and the Analysis results are provided below.

3.1.1 Step 1 – Identify All Available Control Technologies

There are a variety of options available for controlling NOx emissions from heaters and boilers. Some options involve combustion controls that reduce NOx formation, while others utilize add-on-control devices to remove NOx after it is formed. Combinations of combustion controls and add-on controls can be used to reduce NOx emissions. However, Ecology requested that the Analysis include only the following two control technologies:

- LNBs/ULNBs; and
- SCR.

Below we discuss these two control technologies, which are used to reduce NO_X emissions from heaters and boilers.

3.1.1.1 LNBs and ULNBs

LNBs and ULNBs have been grouped together because they are best represented as a category of combustion-control NO_X emission reduction techniques. Additionally, LNB and ULNB terminology can be interchangeable. For instance, in the case of two different burners able to achieve the same NO_X emissions level in identical applications, one burner may be referred to as an LNB, while the second burner is referred to as a ULNB. LNB and ULNB NO_X emission reduction techniques are typically able to achieve 0.055 to 0.060 lb NOx/MMBtu for forced and balanced draft heaters with air preheaters.[6] This Analysis does not evaluate reducing the thermal efficiency of a heater/boiler by removing an existing air preheater.

Combustion-control NO_X emission reduction techniques incorporate one or more of the following concepts: 1) lower flame temperatures; 2) creation of fuel-rich conditions at the maximum flame temperature; and 3) reduced residence time under oxidizing conditions.

LNBs/ULNBs are available in a variety of configurations and burner types. In LNBs/ULNBs, fuel and air are often pre-mixed prior to combustion, resulting in a lower and more uniform flame temperature. Such burners may require the aid of a blower to mix the fuel with air before combustion takes place. Therefore, in a retrofit scenario, the conversion of an existing natural-draft external combustion device to a mechanical-draft design can be costly due to technical difficulties, space issues, and the potential for extensive physical changes to the combustion device.

Internal flue gas recirculation (FGR) involves recycling a portion of a combustion device's exhaust gases back into the unit's burner(s) and is a common design feature of ULNBs that reduces the burner flame temperature.

[6] Balanced draft heaters at the Refinery include combustion air preheaters, which increase the overall thermal efficiency of the heater and reduce fuel usage, but generate additional NO_X as a result of greater flame zone temperatures.

LNBs/ULNBs can also feature staged combustion, which uses a fuel-rich zone to get combustion started and a fuel-lean zone to stabilize the flame, complete combustion, and reduce the peak flame temperature. These burners can also be designed to reduce hot spots and lower NO_X emissions by spreading flames over a larger area. Some units utilize sophisticated controls to maintain flame stabilization, emissions levels, and efficiency across a wide range of turndown ratios.

3.1.1.2 SCR

SCR is a post-combustion exhaust treatment technology that uses a catalyst to promote the chemical reduction of NO_X to molecular nitrogen and water at lower temperature than it would otherwise occur. SCR can reduce NO_X reductions up to 95 percent; however, NO_X emission reductions between 80 and 90 percent are more typical. SCR systems mix a reducing agent, typically aqueous or anhydrous ammonia or urea, with NO_X-containing combustion gases, and pass the resulting mixture through a catalyst bed, which lowers the activation energy required to initiate the NO_X reduction reactions. In the catalyst bed, NO_X and ammonia are adsorbed onto the catalyst surface where an activated complex is formed and the catalytic reduction of NO_X occurs, resulting in nitrogen and water, which desorb from the catalyst surface into the combustion exhaust gas, which is emitted to the atmosphere. SCR systems are available that can effectively operate at temperatures as low as 375 °F and as high as 1,100 °F, though specific catalysts operate over much narrower temperature ranges.

3.1.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, Ecology's requested NO_X emission control technologies were identified for heaters and boilers. Below we discuss which of these technologies are technically feasible as retrofits to control NO_X emissions from each of the nine Refinery emission units.

3.1.2.1 LNBs and ULNBs

Conventional burners can be retrofitted to reduce their NOx emissions with either LNBs or ULNBs. However, each burner has specific retrofit requirements and is not necessarily suited for all heater and boiler applications. The key technical feasibility criterion of a retrofit is whether the heater or boiler can accommodate the longer flame pattern that is characteristic of LNBs and ULNBs.

Three of the Refinery emission units evaluated in the Analysis already have LNBs/ULNBs installed. The feasibility of retrofitting conventional burners with LNBs/ULNBs is discussed for each individual emission unit in Step 4 below.

3.1.2.2 SCR

SCR is technically feasible for all refinery heaters and boilers.

3.1.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Based on this Analysis, the most effective remaining technologies for the heaters and boilers in decreasing order of effectiveness are:

- LNBs/ULNBs plus SCR (vendor guarantees control and the less effective of 95% or 5ppm);
- SCR (95% or 5ppm, whichever results in higher emissions); and
- LNBs/ULNBs (vendor guarantee).

The control effectiveness of LNBs/ULNBs technology was based on the higher predicted NOx guarantee of the vendor guarantees obtained for each specific heater, with some adjustment based on Refinery process knowledge.

Based on discussions with vendors, the most stringent control effectiveness that can be expected for SCR is 95% control or 5 ppm NOx, whichever results in higher emissions. This control effectiveness was conservatively selected for this Analysis because vendors are generally unable to guarantee NOx concentrations below 5 ppm. More typical manufacturer guarantees from recent Refinery SCR installations are for 90% control and 10 ppm NOx. Placing an LNB in front of a SCR will reduce the amount of NOx entering the SCR; however, the overall emission rate for this Analysis is conservatively based on the control efficiency of the SCR – 95% or 5 ppm, whichever results in higher emissions.

3.1.4 Step 4 – Four-Factor Analysis Results

Four aspects were included in this step of the Analysis: costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life. Only those technologies deemed to be technically feasible were evaluated in this step.

3.1.4.1 Cost of Compliance

BP is using available LNB/ULNB and SCR capital cost data from the 2010 Best Available Retrofit Technology (BART) analysis that were developed for BP by Jacobs Engineering (Jacobs). Jacobs based its SCR capital cost estimates on installing aqueous ammonia systems, instead of anhydrous ammonia systems, based on BP's internal risk management requirements to limit potential process safety concerns with storage and handling of anhydrous ammonia at the Refinery. Jacobs provided either "Appraise" or "Select" capital costs for seven of the nine emission units in the Analysis. Jacob's Appraise and Select cost estimation methodology is described in detail below.

<u>Appraise Cost Estimates</u>

Capital costs for control options were developed primarily by scaling historical costs from projects executed by Jacobs and/or by applying Lang Factors, which are published cost estimation factors, and field condition factors to preliminary estimated costs for major pieces of control equipment. This accounts for such items as foundations, piping, electrical, instrumentation, labor, engineering, accessories, and auxiliaries, etc.

Equipment budget pricing was obtained from vendors or using common unit pricing values. Preliminary equipment sizes were based on initial process performance calculations. Scaling using the six tenths method was also used to extrapolate equipment budget pricing from known equipment pricing of differing size as follows:

$$C_2 = C_1 \times \left(\frac{Q_2}{Q_1} \right)^{0.6}$$

where:

C_1	=	Known Cost of Equipment
C_2	=	Estimated Cost of New Equipment
Q_1	=	Capacity of Known Cost Equipment

Q_2 = Capacity of New Equipment

The BART cost analysis included a 40 percent contingency factor, which is the industry standard for budgetary Appraise-level cost estimates. The contingency addresses details not explicitly included in the budgetary capital cost estimate, including: generic instrumentation, construction and field expenses, and contractor fees. BP revised the Jacobs contingency factor from 40 percent down to 15 percent, from EPA's OAQPS cost manual for SCR, to provide more conservative cost calculations.[7]

The BART cost analysis also addressed costs related to retrofitting the existing units. The installed cost for the SCR was multiplied by a retrofit factor of 1, 1.1, or 1.3, depending upon the complexity of installing an SCR into the existing available space.

The cost analysis also addressed: cost of catalyst, run life of catalyst and turn around cycles, installation and operation of continuous emission monitoring systems (CEMS), maintenance costs related to installation of additional fans, handling and storage of chemicals such as ammonia, installation of Safety Instrumented Systems (SIS), and electrical infrastructure expansion, when necessary.

Appraise cost estimates were used for the South Vacuum Heater, Naphtha HDS Charge Heater, Naphtha HDS Stripper Reboiler, and Hydrocracker R-4 Heater.

<u>Select Cost Estimates</u>

Select cost estimates were based on more project-specific information than the Appraise cost estimates. Using process flow diagrams (PFDs), piping and instrumentation diagrams (P&IDs), similar equipment review, and process knowledge, Jacobs estimated the equipment, demolition, site work, pilings, buildings, concrete, structural steel, ducting, piping, insulation, instrumentation, electrical, painting, scaffolding, and fire protection requirements for each emission unit and control option. Using these estimates, both installation and operating costs for each emission unit/control option pairing were generated.

The design assumptions and design basis for the SCR and the ammonia skid used in the Select cost estimates are outlined in figures in Attachment A. Select cost estimates were used for the Crude Charge Heater, #1 Reformer Heaters, and #1 Hydrogen Plant Furnaces.

Jacobs also obtained LNB quotes to identify the lowest NOx burners capable of performing at any heater load (i.e., maximum heater release, normal operation, and minimum turndown conditions).

Material pricing was based on the data available in Jacobs' in-house databases. In addition, labor costs required for the installation were estimated. Labor estimates were based on Jacobs' standards and actual costs for similar work. Jacobs obtained quotes from vendors for the major equipment for each specific project, including burner items, SCR equipment, testing costs, and electrical equipment.

[7] EPA's OAQPS Cost Manual, Section 4, Chapter 2 (Selective Catalytic Reduction). June 2019.

The Select cost estimate also addresses:

- Freight costs: Jacobs assumed freight costs to be six percent of material cost. Freight for the air preheaters associated with the SCR installation, if required, was included in the equipment cost.

- Design allowance: A contingency included in each category of expense (e.g., equipment, demolition, site work, etc.) to cover costs that are known to occur, but for which no information was available at this stage of design. Based on Jacobs' experience, design allowances vary between 10 and 20 percent of the cost in that equipment category and are based on historical information.

- Sales tax: Sales tax was excluded from the analysis for all but rental costs.

- Productivity: When the labor costs were estimated, the efficiency, or productivity, of each discipline/trade was included to create realistic estimates of actual labor hours from which costs were calculated.

- Construction: Labor rates are based on direct hire construction as provided by BP. These rates include base salary, fringe benefits, payroll taxes and insurance, small tools, and overhead.

- Field Indirects: Included in the all-in wage rate; incorporates construction services labor, temporary field services, non-payroll taxes, insurance, small tools, consumables and construction equipment, and field staff.

- Professional Services: Includes front-end scoping services, detailed engineering and design, procurement, construction support, project representation, and as-builts/closeouts.

- Client Costs: Based on Jacobs' experience, client costs were estimated at 8 percent.

- Contingency: The cost estimate for each unit and control pairing was reviewed using a Monte Carlo risk assessment model to determine the reliability of the components of the cost estimate and, based on this review, assign a project-specific contingency factor. The contingency factors ranged from approximately 17 to 20 percent of the total installed construction cost including equipment, materials, engineering, and construction. This contingency is part of the estimated job cost and is to cover items which have been inadvertently left out of the estimate, minor delays in deliveries of equipment or materials, etc. It does not cover the cost of additional work or scope changes after the definition of the job has been frozen for the estimate.

- Commercial Loss: Installations for individual control options will be associated with currently scheduled cycle ending TARs for the various emission units affected, which range from the years 2021 to 2026. Each TAR has a specific number of planned days for the work required for scheduled capital and maintenance for that emission unit. Potential LNB or SCR additions to heaters were evaluated against the already planned number of days by the refinery TAR Planning group. If the additional scope added days to the TAR, lost revenue for those days was calculated and incorporated into the cost calculation. If no additional days were needed, there was no impact to the TAR, no lost revenue and no impact to the cost calculation.

Both Appraise and Select cost estimates include the installation of the safety instrumented system (SIS) and the CEMS. SIS is an upgrade to the control system for combustion units that is required by the OSHA Process Safety Management (PSM) standard. It was assumed that installation of both the SIS, if not already installed, and a CEMS would be included with any selected control option. However, when examining combined technologies (e.g., LNB plus SCR), the SIS and CEMS costs were only included once.

Both Appraise and Select cost estimates were based on a single SCR catalyst bed. Due to time constraints for preparing this Analysis, the capital costs for SCR systems are conservatively low compared to current design criteria (i.e., dual catalyst bed system to prevent bypassing the SCR if catalyst plugging occurs and/or bypassing the SCR if the catalyst is consumed quicker than the planned turnaround schedule).

The Jacobs Appraise and Select cost data are expressed in 2007 dollars. BP used the Nelson Farrar Refinery Construction cost index to calculate 2007 dollars into 2020 dollars, which corresponds to an approximately 41 percent increase in capital costs.[8]

OAQPS Cost Estimates

The #5 Boiler and the #2 Reformer Heaters were not evaluated in the 2010 BART analysis; therefore, neither Appraise nor Select cost data are currently available from Jacobs. BP used available SCR capital cost data from EPA's OAQPS Control Cost Manual with recent refinery-based cost adjustments completed by South Coast Air Quality Management District (SCAQMD).

EPA's SCR cost model estimates SCR installation costs based on data from the electrical power sector, specifically for large utility boilers. As part of current rulemaking activities for petroleum refineries, SCAQMD updated the SCR total capital investment cost estimation equation to include cost estimate data provided by local refineries.[9] BP used the SCAQMD capital cost equation as a screening level SCR cost estimate for this Analysis. A more detailed Appraise or Select cost estimate would result in higher SCR capital costs compared to the SCAQMD capital cost equation.

The OAQPS Control Cost Manual for SCRs is also used to calculate annual operating labor costs, maintenance costs, reagent usage, and administrative charges for all SCR control options in the Analysis. Refinery-specific reagent costs and electricity costs are incorporated into the cost calculations.

[8] The Nelson Farrar Refinery Construction cost escalation index values for 2007 and 2020 are 2106.7 and 2979.0, respectively.

[9] SCAQMD adjustments to SCR installation total capital investment presented and discussed in December 12, 2019 working group meeting for Rule 1109.1 (Slide 21 on presentation accessible here: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12)

As discussed in the following sections, time necessary for compliance, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life were included in the Analysis as appropriate.

3.1.4.2 Time Necessary for Compliance

Implementing NOx control strategies would need to follow the Refinery maintenance TAR schedule (5 to 6-year schedule per emission unit) or risk extending the facility maintenance outage and lost production.[10] The scope of each TAR is locked years prior to the actual start of each maintenance turnaround based on necessary engineering design, installation planning, permitting, site preparation, contractor scheduling, installation, commissioning, and startup requirements. BP estimates a schedule of 7 to 10 years would be required to implement additional NOx control strategies.

3.1.4.3 Energy and Non-Air Quality Environmental Impacts

Energy impacts were evaluated for each technically-feasible emission unit and control technology combination. Evaluations of energy use were based on discussions with BP and Jacobs specialists. Costs of energy were provided by the BP Energy Specialist based on Refinery norms as used for other projects.

Several energy penalties were addressed in the operating costs, including electricity consumption for additional use of larger support equipment (e.g., fans), and electricity use of the control technologies (e.g., ammonia vaporization for SCR).

Non-air quality environmental impacts associated with each potential control technology were reviewed. Any costs incurred from the handling and treatment of by-products and wastes were included in the cost analysis.

The spent SCR catalyst is the only waste stream identified in the cost analysis for NOx control on refinery heaters. The cost analysis assumes that the SCR catalyst has a five-year life. Spent catalyst will require off-site disposal or recycling. Also, storing quantities of ammonia on-site for use in a SCR may require an update to the refinery’s Risk Management Plan (RMP).

For fired units, implementation of certain NOx control technologies would introduce new emissions (e.g., ammonia from SCRs) or cause an increase in existing emissions (e.g., particulate matter emissions from SCRs).

LNB and ULNB, as well as conventional burners, are capable of low CO emissions when fired at normal to maximum design capacities. Typically, this is the point at which the vendor will guarantee the CO levels. However, as the burner is turned down, LNB/ULNB will usually produce higher CO levels than a conventional burner. As such, any permit limits resulting from the Analysis should be set to accommodate these variations in emissions due to changes in operation.

[10] Regardless of TAR planning, implementing NOx control strategies on specific emission units will result in extended process unit downtime during the TAR. Lost revenue due to implementing the control strategy is incorporated into the Cost of Compliance calculations.

The SCR technology removes NOx from the exhaust stream by injecting ammonia into the flue gas as it passes through a catalyst bed. A balance must be struck: enough ammonia must be injected to react with as much NOx as possible, but any unreacted ammonia will escape with the flue gas and cause ammonia emissions. The ammonia that escapes is called "ammonia slip." The SCRs in this Analysis are being designed to a hypothetical 5 parts per million by volume dry (ppmvd) ammonia slip at 3 percent oxygen during normal operation. Actual vendor guarantee ammonia slip concentrations for recent Refinery installations were 10 ppmvd at 3 percent oxygen. In addition, sulfur in refinery fuel gas can combine with the ammonia injected into the SCR to produce ammonium bisulfate particulate matter emissions.

3.1.4.4 Remaining Useful Life

The remaining useful life is considered in determining the annualized cost when evaluating the control options. As the remaining useful life gets shorter, the annualized cost increases. In this Analysis, the remaining useful life for all emission units and control devices was assumed to be the same as for new equipment, 25 years. This assumption means that there is no discounting of the cost to account for a shorter life-span. The catalyst life for SCR is assumed to be five years.

The controlled emission factors, controlled emission rates, cost effectiveness and incremental cost effectiveness values for each unit and control device are summarized in Table 3-1. Further detail and supporting calculations are discussed in the following sections.

3.1.4.5 Crude Charge Heater

The Crude Charge Heater is currently fitted with conventional burners.

LNBs/ULNBs: Installing LNBs/ULNBs on the Crude Charge Heater is not technically feasible due to safety concerns. A LNB/ULNB retrofit would result in a serious safety concern and an operational risk based on flame impingement (the longer flame from ULNB contacts the heater tubes, reducing the tube life, and potentially resulting in tube failure) and the high heat density (total firing rate divided by heater cross-sectional area).[11] The calculated heat density for the Crude Charge Heater is 470,000 Btu/ft^2-hr, which is well above the acceptance criteria for retrofitting LNBs/ULNBs, which is 350,000 Btu/ft^2-hr.

In order to satisfy the retrofit heat density criteria, BP would need to rebuild the Crude Charge Heater (increase the heater diameter) to accommodate the burner retrofit. The cost to rebuild the heater is very difficult to estimate and would likely exceed the cost of purchasing a new Crude Charge Heater. Also, the time required to rebuild the Crude Charge Heater would significantly increase the length of the maintenance TAR and associated lost production at the Refinery.

SCR: The cost-effectiveness analysis to install a SCR on the Crude Charge Heater is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $32,049/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

LNBs/ULNBs + SCR: Because LNB/ULNB installation is technically infeasible, the combination of LNB/ULNB and SCR is also technically infeasible.

BP proposes that good combustion practices following 40 CFR Part 63, Subpart DDDDD tune-up requirements satisfy the Analysis for the Crude Charge Heater.

3.1.4.6 South Vacuum Heater

The South Vacuum Heater is currently fitted with ULNBs (Northwest Clean Air Agency [NWCAA] Order of Approval to Construct [OAC] #902, February 7, 2005, revised November 1, 2005).

LNBs/ULNBs: ULNBs have already been installed on the South Vacuum Heater. Further NOx reduction is not possible using burner upgrades due to the high air preheat and high heat density.

SCR: The cost-effectiveness analysis to install a SCR on the South Vacuum Heater is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $60,160/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

BP proposes that the existing ULNBs satisfy the Analysis for the South Vacuum Heater.

[11] The heat density is a criterion for predicting LNB performance when installed in a process heater, and the criteria was developed in response to several LNB installations were heater performance was significantly worse than theoretical test heaters.

3.1.4.7 Naphtha HDS Charge Heater and Naphtha HDS Stripper Reboiler

The Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler are currently fitted with conventional burners.

LNBs/ULNBs: Installing LNBs/ULNBs on the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler is not technically feasible due to safety concerns related to flame impingement on the heater tubes and high heat density; therefore, this control option was eliminated. The calculated heat density for the Naphtha HDS Charge Heater and Stripper Reboiler are 682,000 Btu/ft^2-hr and 786,000 Btu/ft^2-hr, which are well above the acceptance criteria for retrofitting LNBs/ULNBs

BP would need to rebuild both heaters to prevent flame impingement resulting from the burner retrofit. The cost to rebuild the heaters are very difficult to estimate and would likely exceed the cost of purchasing new Naphtha HDS Heaters.

SCR: The cost-effectiveness analyses to install SCRs on the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler are included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $70,260/ton for the Naphtha HDS Charge Heater and $43,854/ton for the Naphtha HDS Stripper Reboiler, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

LNBs/ULNBs + SCR: Because LNB/ULNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP proposes that good combustion practices following 40 CFR Part 63, Subpart DDDDD tune-up requirements satisfy the Analysis for the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler.

3.1.4.8 #1 Reformer Heaters

The #1 Reformer Heaters are a complex design of four independent fire boxes and two stacks. The heater is currently fitted with conventional burners.

LNBs/ULNBs: Installing LNBs/ULNBs on the #1 Reformer Heaters is not technically feasible due to safety concerns from flame impingement. The existing burners produce the shortest, most compact flame available, and LNB/ULNB would produce a longer flame, which would be more susceptible to heater currents and expected to result in much greater levels of flame impingement. As such, LNB/ULNB are considered technically infeasible and are eliminated from consideration.

BP would need to rebuild the heaters to prevent flame impingement resulting from the burner retrofit. The costs to rebuild the heaters are very difficult to estimate and would likely exceed the cost of purchasing new #1 Reformer Heaters.

SCR: The cost effectiveness analysis to install a SCR on the #1 Reformer Heaters is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $24,378/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

LNBs/ULNBs + SCR: Because LNB/ULNB installation is technically infeasible, the combination of LNB/ULNB and SCR is also technically infeasible.

BP proposes that good combustion practices following 40 CFR Part 63, Subpart DDDDD tune-up requirements satisfy the Analysis for the #1 Reformer Heaters.

3.1.4.9 #2 Reformer Heater

The #2 Reformer Heater is currently fitted with LNBs (Ecology issued Prevention of Significant Deterioration [PSD] -7, March 13, 1986).

LNBs/ULNBs: LNBs have already been installed on the #2 Reformer Heater. Further NOx reduction is not possible using burner upgrades based on computational fluid dynamics (CFD) modeling that was completed in in 2008 as part of a potential ULNB retrofit project. The CFD modeling indicated that a ULNB retrofit would result in significant flame impingement and tube skin temperatures in excess of metallurgy limits. As such, ULNB retrofit was considered technically infeasible due to safety concerns and eliminated from consideration.

SCR: The cost-effectiveness analysis to install a SCR on the #2 Reformer Heater is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $29,289/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

BP proposes that the existing LNBs satisfy the Analysis for the #2 Reformer Heater.

3.1.4.10 Hydrocracker R-4 Heater

The R-4 Heater is currently fitted with conventional burners.

LNBs/ULNBs: Installing LNBs/ULNBs on the R-4 Heater is not technically feasible due to safety concerns from flame impingement, high heat density, flame shape, and an exceedance of the API guidelines for burner spacing. The calculated heat density for the R-4 Heater is 723,000 Btu/ft^2-hr, which is well above the acceptance criteria for retrofitting LNBs/ULNBs

BP would need to rebuild the heater to prevent flame impingement resulting from the burner retrofit. The cost to rebuild the heater is very difficult to estimate and would likely exceed the cost of purchasing new R-4 Heater.

SCR: The cost-effectiveness analyses to install SCR on the R-4 Heater is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $23,194/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

LNBs/ULNBs + SCR: Because LNB/ULNB installation is technically infeasible, the combination of LNB/ULNB and SCR is also technically infeasible.

BP proposes that good combustion practices following 40 CFR Part 63, Subpart DDDDD tune-up requirements satisfy the Analysis for the R-4 Heater.

3.1.4.11 #1 Hydrogen Plant Furnaces

The #1 Hydrogen Plant North and South Steam Reforming Furnaces are currently fitted with conventional burners.

LNBs/ULNBs: The cost-effectiveness analysis for installation of ULNBs on the #1 Hydrogen Plant Furnaces (replacing 384 burners per furnace) is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness value of $49,432/ton, ULNBs would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

SCR: The cost-effectiveness analysis to install a SCR on the #1 Hydrogen Plant Furnaces is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $78,082/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

LNBs/ULNBs + SCR: The cost-effectiveness calculation assumes that the ULNB installation cost would not change as a result of the SCR installation. The cost of SCR was reduced to account for a lower post-ULNB NOx concentration resulting in reduced catalyst requirements and ammonia consumption. The cost-effectiveness analysis to install ULNB and SCR on the Furnaces is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $84,156/ton, ULNBs and SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

BP proposes that good combustion practices following 40 CFR Part 63, Subpart DDDDD tune-up requirements satisfy the Analysis for the #1 Hydrogen Plant Furnaces.

3.1.4.12 #5 Boiler

The #5 Boiler is currently fitted with ULNBs and external flue gas recirculation (Ecology issued PSD-02-04 Amendment 1 on April 20, 2005).

LNBs/ULNBs: ULNBs have already been installed on the #5 Boiler. Further NOx reduction is not possible as the current burners achieve annual average NOx emissions of 0.030 lb/MMBtu heat input based on 2016 CEMS data.

SCR: The cost-effectiveness analysis to install a SCR on the #5 Boiler is included in Table 3-1 and detailed information is provided in Attachment B. With a cost effectiveness of $126,958/ton, SCR would not be considered cost-effective in a top-down BACT analysis and should therefore be eliminated from the Analysis.

BP proposes that the existing ULNBs satisfy the Analysis for the #5 Boiler.

TABLE 3-1. SUMMARY OF COSTS DEVELOPED FOR NOX FOR REFINERY HEATERS

Source	Baseline Fired Duty (MMBtu/hr)	Baseline NOx tons/year	NOx Controlled Emission Factors (lb/MMBtu)			NOx Controlled Emissions (tons/year)			NOx Emission Reduction (tons/year)			Total Annual Cost ($MM)[1]			NOx Control Cost Effectiveness ($/ton)[1]			Incremental $/ton	
			LNB/ULNB (3)	SCR (4)	ULNB + SCR	ULNB	SCR	ULNB + SCR	ULNB	SCR	ULNB + SCR	ULNB	SCR(4)	ULNB + SCR	ULNB	SCR	ULNB + SCR	ULNB to SCR	SCR to SCR + ULNB
Crude Charge Heater	584	444	technically infeasible	0.0087	technically infeasible	-	22.2	-	-	421.5	-	-	**13.5**	-	-	**32,049**	-	-	-
South Vacuum Heater	165	37	already installed	0.0060	0.0060	-	4.4	4.4	-	32.5	32.5	-	2.0	2.0	-	60,160	60,160	-	-
Naphtha HDS Charge Heater	53	20	technically infeasible	0.0053	technically infeasible	-	1.2	-	-	19.0	-	-	1.3	-	-	70,260	-	-	-
Naphtha HDS Stripper Reboiler	69	26	technically infeasible	0.0053	technically infeasible	-	1.6	-	-	24.7	-	-	1.1	-	-	43,854	-	-	-
#1 Reformer Heaters	631	338	technically infeasible	0.0061	technically infeasible	-	16.9	-	-	449.2	-	-	**7.8**	-	-	**24,378**	-	-	-
#2 Reformer Heater	135	67	already installed	0.0058	0.0058	-	3.4	3.4	-	35.3	35.3	-	1.9	1.9	-	29,289	29,289	-	-
Hydrocracker R-4 Heater	52	28	technically infeasible	0.0060	technically infeasible	-	1.4	-	-	16.6	-	-	0.6	-	-	23,194	-	-	-
#1 Hydrogen Plant Furnaces	351	151	0.055	0.0060	0.0060	84.5	9.2	9.2	47.6	122.8	122.8	**3.3**	**11.0**	**11.9**	**49,432**	**78,082**	**84,156**	103,232	(2)
# 5 Boiler	124	16	already installed	0.0059	0.0059	-	3.2	3.2	-	32.9	32.9	-	1.7	1.7	-	126,958	126,958	-	-

Notes:

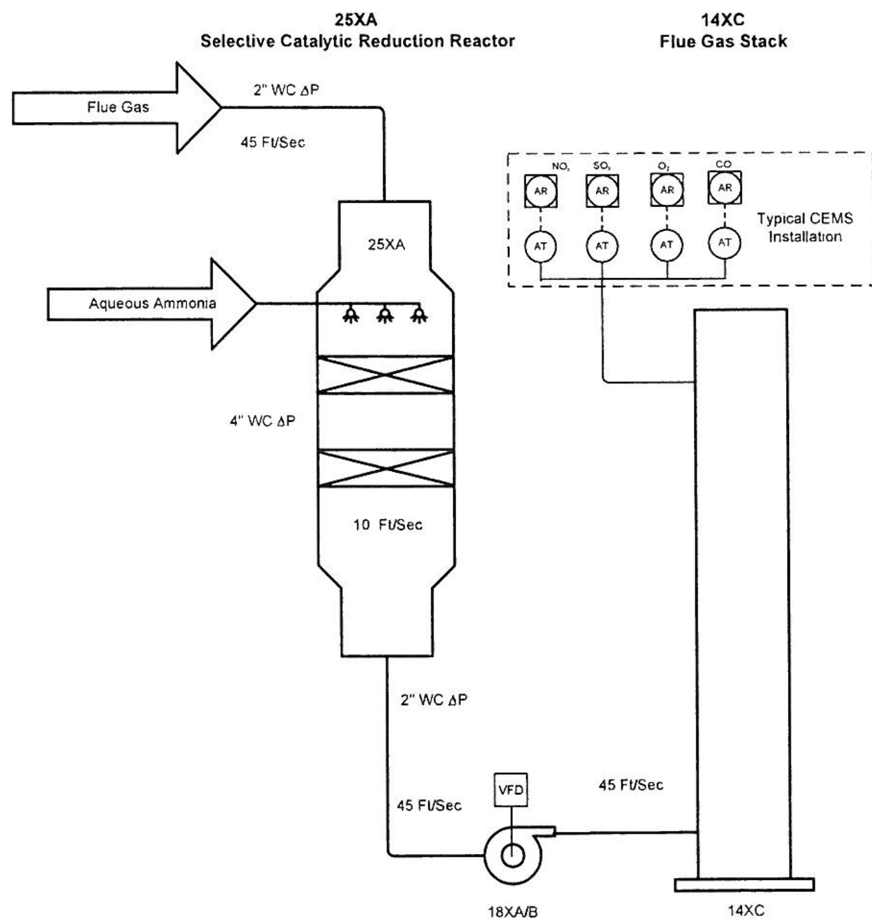
(1) The bolded values are those unit/control pairings where a refined Select cost analysis was performed. An Appraise level cost analysis was used for all the nonbolded values, except #2 Reformer and #5 Boiler (based on EPA's OAQPS Cost Manual with SCAQMD adjustments).

(2) A number cannot be generated because the quantity of emissions would not change (i.e., the denominator equals 0).

(3) The controlled emission factors for the LNB/ULNB are based on vendor guarantees.

(4) The controlled emission factor for the SCR based on a control efficiency of 95% or 5 ppm, whichever results in greater emissions.

Attachment A



18XA/B
Induced Draft Fan & Spare

Input	Crude Charge heater Induced Draft	Crude Charge heater Forced Draft	#1 Reformer	Hydrogen	Hydrogen
Mw	27.78	28.81	27.78	27.78	27.78
k,cp/cv	1.35	1.41	1.35	1.35	1.35
Zsuction	1.00	1.00	1.00	1.00	1.00
Psuction, psia	14.12	14.62	14.48	14.37	14.37
Tsuction, °F	450.00	60.00	750.00	750.00	750.00
Pdischarge, psia	14.70	15.13	14.70	14.70	14.70
Zdischarge	1.00	1.00	1.00	1.00	1.00
Isoenthalpic,eff	0.70	0.70	0.70	0.70	0.70
Flow Rate,MMSCFD	170.72	156.60	204.16	88.58	86.85
Output					
Density, suction lb/ft³	0.04	0.08	0.03	0.03	0.03
Ts, °R	909.70	519.70	1,209.70	1,209.70	1,209.70
Tdisch, Pred °F	463.56	67.36	756.66	760.03	760.03
W,Lb/min	8,678.45	8,255.83	10,378.36	4,502.91	4,414.97
W, Lb/Hr	520,707	495,350	622,701	270,175	264,898
r (Pd/Ps)	1.04	1.03	1.01	1.02	1.02
ACFM	215,972.01	109,271.44	334,899.15	146,397.93	143,538.72
MMSCFD	170.72	156.60	204.16	88.58	86.85
Head	2,036.25	950.28	999.47	1,506.28	1,506.28
Gas Horsepower	765.00	339.63	449.04	293.62	287.89
dp, inches w.c.	16.00	14.00	6.00	9.00	9.00
115% factor, HP	879.75	390.57	516.40	337.67	331.07
Motor with 1.1 factor	967.72	429.63	568.04	371.43	364.18
Nominal Motor Size	1,000	500	600	400	400

SCR Design

Design Basis for SCR
95% efficiency, with NOx equal to or greater than 5 ppmvd
5% Ammonia Slip
4 inch w.c. pressure drop
Calculate Catalyst Volume using Jacobs formulae
Catalyst Correction Factor=

$$\text{Catalyst Correction Factor} = 0.08 + \left(\frac{NH3}{NOx}\right) + 0.08\left(\frac{NH3}{NOx}\right)^2 + 0.08\left(\frac{NH3}{NOx}\right)^3 + 0.08\left(\frac{NH3}{NOx}\right)^4 + 0.08\left(\frac{NH3}{NOx}\right)^5$$

Catalyst Activity Facto = 1 - 0.08 • years of run

Catalyst Intrinsic Rate Contstant = $A_o\,e^{HX/*R}$

Space Velocity, Hr = 3600 * Cat Intrinsic Rate Const • Cat Activity Factor • Spec Surf •
Catalyst Correction Factor/(-ln(1 - eff))

Volume = SpaceVelocity,Hr • ACFH

Cross sectional area based on 10 ft/sec
Calculate length, with minimum of 12 feet

Preheaters
5 inch w.c. pressure drop
Do not allow flue gas to run less than 450°F to avoid Ammonia Bisulphate and Ammonia Sulphate precipitation.

Fans

70% efficiency

Required ammonia

NH3 = Moles NOx + 5 ppmv slip

Catalyst
Use MT catalyst
Operating temperature 550 to 750°F

BART Source Point Discription	Peak Design MMBTU/Hr	Combustion air MMSCFD	Flue Gas MMSCFD	SCR Inlet °F	ft³/sec	Ducting: area, ft² at 45 ft/sec	Ducting: Side or Square Duct ft	Reactor: area, ft² at 10 ft/sec	Reactor: Square duct side ft
Crude Charge Heater	593.20	156.60	170.72	750	4599.3	102	10.1	460	21.4
#1 Reformer Heaters	709.40	187.28	204.16	750	5500.2	122	11.1	550	23.5
Reforming Furnace #1 - (North H2 Plant)	307.80	81.26	88.58	632	2153.7	48	6.9	215	14.7
Reforming Furnace #2 - (South H2 Plant)	301.80	79.67	86.85	632	2111.7	47	6.9	211	14.5

	Ducting Downstream of Preheater				Ducting Combustion Air				Ducting Combustion Air				Ducting Combustion Air			
	°F	acfm	area, ft² at 45 ft/sec	Side or Square Duct ft	°F	area, ft² at 45 ft/sec	area, ft² at 45 ft/sec	Side or Square Duct ft	°F	area, ft² at 45 ft/sec	area, ft² at 45 ft/sec	Side or Square Duct ft	°F	area, ft² at 45 ft/sec	area, ft² at 45 ft/sec	Side or Square Duct ft
Crude Charge Heater	450	3,459	76.9	8.8	60	1,813	40.3	6.3	594	3,675	81.7	9.0	309	2,681	59.6	7.7

FILE GENERIC SCR VSD REV 02/21/08 2:30 PM

NO	DATE	REVISION DESCRIPTION	BY	CHK	APPD	NO	DATE	REFERENCE DRAWINGS
								AB-1100-41
								AR-1100-21

APPROVAL

ENGINEERING RECORD		DATE
DRAWN BY	RAJ	11/1/07
DESIGNED BY		
DESIGN CHECKED		
APPROVED BY		
APPROVED BY		
WORK PKG		
SCALE		

bp
BP CHERRY POINT

TITLE OF DRAWING
Generic
SCR Option

PROJECT & MODULE I D		DRAWING NUMBER					SHEET
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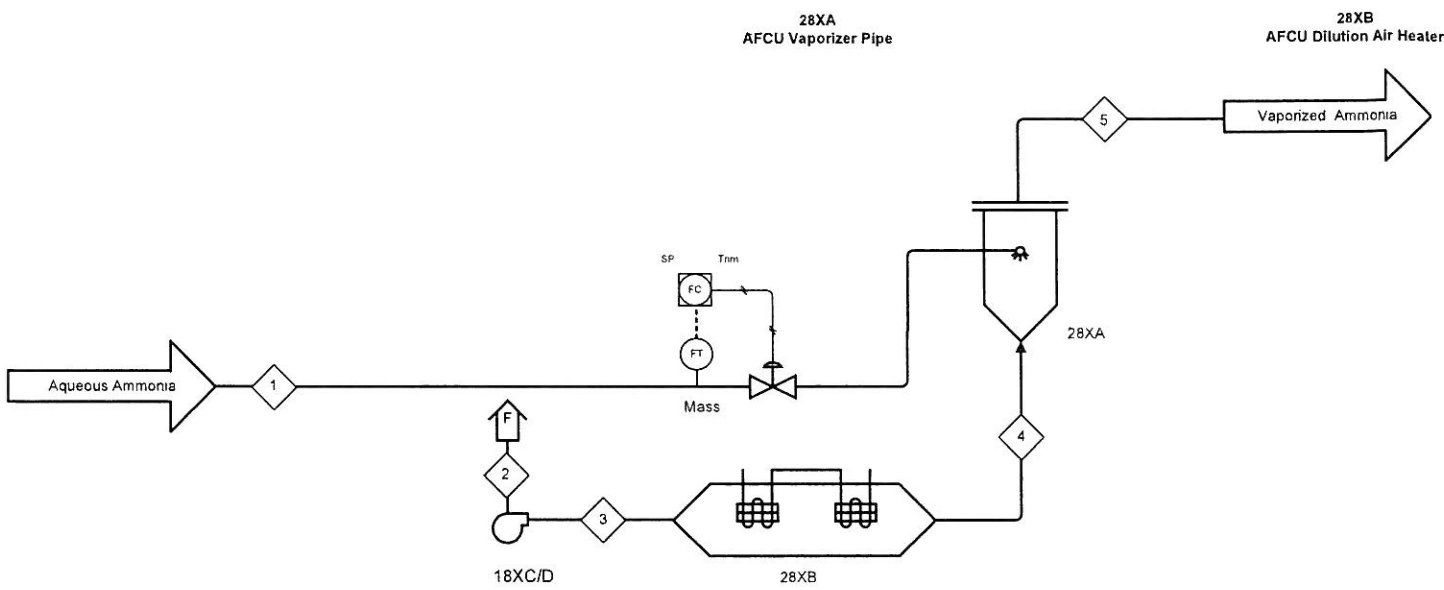
PROJECT	MODULE	DISC	FAC	CONT I D	SEQUENCE NO	REV NO	OF



Vendor Supplied Ammonia Flow Control Unit (AFCU)

Material Balance for 100 lb/hr Aqueous Ammonia

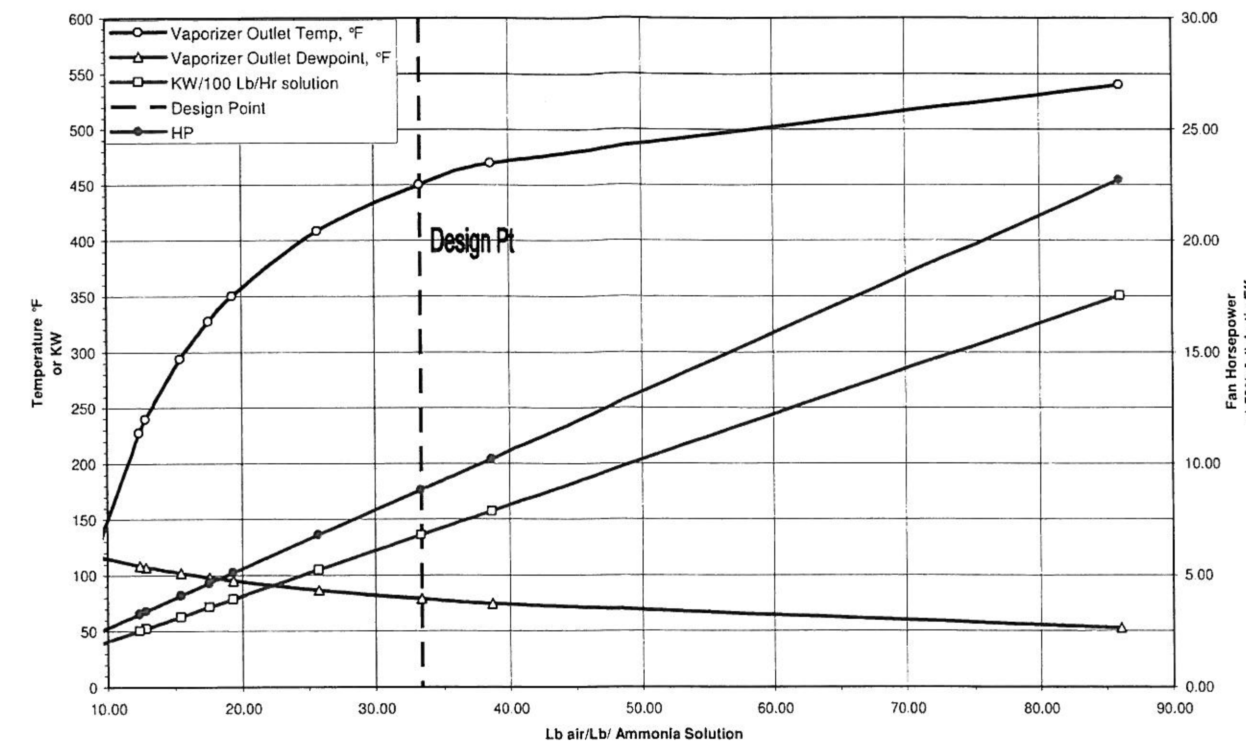
Number	1	2	3	4	5
Air, Mole %	0.00	100.00	100.00	100.00	95.33
NH3, Mole %	30.58	0.00	0.00	0.00	1.43
H2O, Mole %	69.42	0.00	0.00	0.00	3.24
Molar Flow lbmole/hr	5.65	115.27	115.27	115.27	120.91
Pressure,psia	14.70	14.70	16.32	15.20	14.70
Temperature °F	0.00	0.00	28.52	600.00	450.01
Vapour Fraction	0.00	1.00	1.00	1.00	1.00
Mass Flow lb/hr	100.00	3,337.00	3,337.00	3,337.00	3,437.00
GPM @ 60°F	0.237	7.577	7.577	7.577	7.813
MMBtu/Hr	-0.5479	-0.0610	-0.0386	0.4249	-0.1230
Kilowatts	-160.5791	-17.8852	-11.3259	124.5375	-36.0416
Mass Density lb/ft3	55.81	0.0863	0.0902	0.0387	0.0428
Cp/Cv	1.18	1.42	1.41	1.38	1.38
CP ,Btu/lb-°F	1.12	0.24	0.24	0.25	0.25
Viscosity,cp	1.07	0.0167	0.0175	0.0309	0.0267
Thermal Conductivity Btu/hr-ft-°F	0.32	0.0126	0.0132	0.0245	0.0218

Ammonia Injection System							Inlet duct (45 ft/sec)			
Source	lb/hr solution	gpm	Electrical Heater, KW	Electrical Heater, "HP"	Blower HP 50% eff	Dilution air,CFM	Dilution air, ft³/sec	ft²	Diameter duct. Inches	Dilution air, ft³/sec
Crude Charge Heater	135.52	0.3043	183.90	246.42	11.92	873	14.55	0.3234	7.70	13.92
#1 Reformer Heaters	132.41	0.2973	179.68	240.77	11.65	853	14.22	0.3160	7.61	13.60
Reforming Furnace #1 - (North H2 Plant)	38.33	0.0861	52.02	69.70	3.37	247	4.12	0.0915	4.10	3.94
Reforming Furnace #2 - (South H2 Plant)	37.59	0.0844	51.01	68.36	3.31	242	4.04	0.0897	4.06	3.86

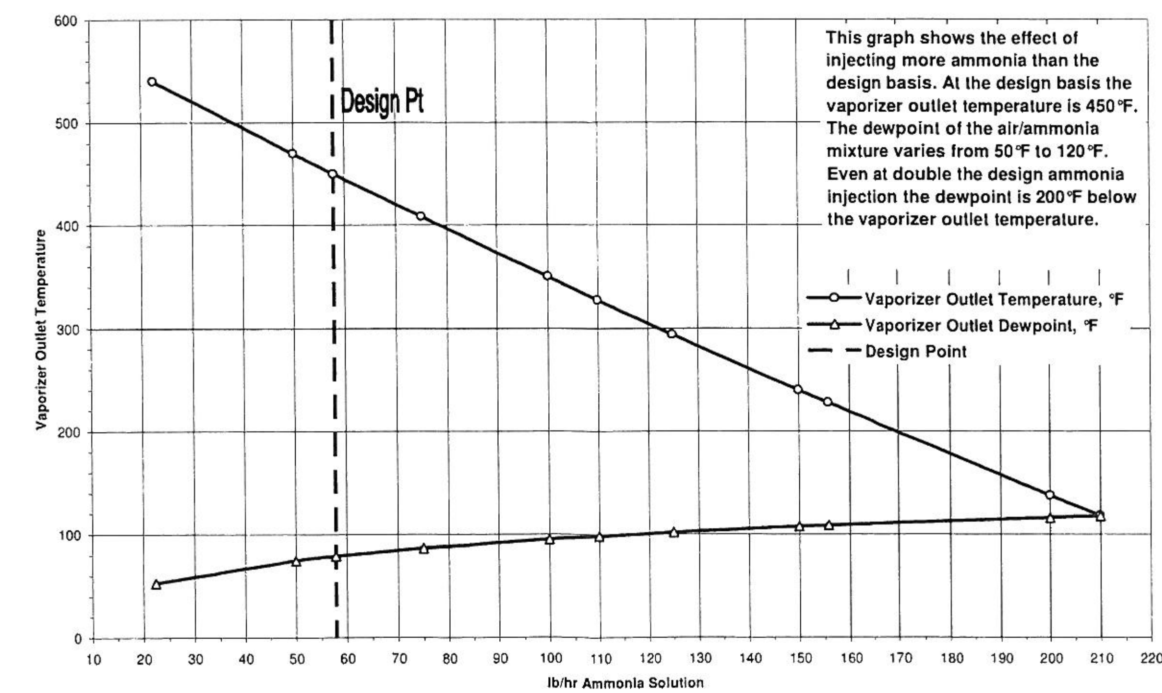
Design basis for the Ammonia injection system is:
Dry air at 0 inches water column (wc) and 0°F
Discharge pressure on fan is 45 inches wc
Fan has 50% adiabatic efficiency
Heat up air to 600°F
Inject Ammonia (also at 0°F)
Combined Ammonia and Air is 450°F – this is accomplished by setting the ammonia flow rate at 100 lb/hr and changing the air rate to accomplish this.

The heat and material balance from the above design is Prorated based on the actual required ammonia for each Source (Crude Charge Heater, etc).

Ammonia Vaporizer
29.4 Wt% Ammonia



Ammonia Vaporizer
Dilution Air fixed at 1,932.5 Lb/Hr



18XC/D
AFCU Dilution Air Fan & Spare

FILE AMMONIA SKID.VSD REV 02/05/08 8:15 AM

NO	DATE	REVISION DESCRIPTION	BY	CHK	APPD	NO	DATE	REFERENCE DRAWINGS
								AB-1400-40
								AR-1400-20

APPROVAL

ENGINEERING RECORD		DATE
DRAWN BY	RAJ	11/1/07
DESIGNED BY		
DESIGN CHECKED		
APPROVED BY		
APPROVED BY		
WORK PKG		
SCALE		

bp
BP CHERRY POINT

TITLE OF DRAWING: Ammonia Skid Design Basis

PROJECT & MODULE I.D.		DRAWING NUMBER						SHEET
	–	SK –	14 –	XX –	PFD 1	– 0	D	0 0 1
PROJECT	MODULE	DISC	FAC	CONT I.D.	SEQUENCE NO		REV.NO.	OF

Attachment B

BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - Crude Charge Heater
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
A. Equipment Design Considerations		
a. SCR Cost (including adjustment for SCR reactor height and bypass installation)	$70,660,573	Jacobs Select Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)	$3,400,814	Jacobs Select Cost Estimate w/escalation
c. Initial Charge of Catalyst	$968,914	Jacobs Select Cost Estimate w/escalation
d. ID Fan Cost (included in SCR Cost)	$0	Jacobs
e. ID Fan Motor Cost (included in SCR Cost)	$0	Jacobs
f. Convection Section Cost (included in SCR Cost)	$0	Jacobs
g. Duct Work Cost (included in SCR Cost)	$0	Jacobs
h. Plot Plant Installation Factor (included in SCR Cost)	1	Jacobs
Primary Equipment Total Installed Cost	$75,030,301	*Calculation*
i. SIS Instrumentation	$5,854,208	Jacobs Select Cost Estimate w/escalation
j. CEMS Installation	$3,125,072	Jacobs Select Cost Estimate w/escalation
k. Local Sales tax (included in SCR Cost)	$0	Jacobs
l. Freight (included in SCR Cost)	$0	Jacobs
Total Direct Capital Cost [DCC]	$84,009,582	
INDIRECT COSTS		
B. Indirect Installation		
a. General Facilities (included in SCR Cost)	$0	Jacobs
b. Engineering and Home Office Fees (included in SCR Cost)	$0	Jacobs
c. Process Contingency (included in SCR Cost)	$0	Jacobs
Total Indirect Costs [ICC]	$0	*Calculation*
C. Project Contingency (included in SCR Cost)	$0	Jacobs
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)	$84,009,582	*Calculation*
D. Lost Production due to extended turnaround	$90,000,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]	$174,009,582	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)	**$12,346,407**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT ANNUAL COSTS (DAC)		
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)	$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])	$420,048	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (137 lb reagent/hr * 8,234 hr/yr * $0.33/lb reagent)	$372,839	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)	$175,349	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (490 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 8,234 hrs/yr * $0.033/kWh)	$99,371	Jacobs
Total Direct Annual Costs [DAC]	$1,155,206	
INDIRECT ANNUAL COSTS (IDAC)		
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))	$7,669	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]	$12,354,076	
Total Annual Cost [TAC] (DAC+IDAC)	**$13,509,282**	*Calculation*
Uncontrolled emissions — tons/year	443.7	2016 Actuals
Emissions w/SCR — tons/year	22.2	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline — Percent	95.0	*Calculation*
Total Emissions Reduction — tons/year	421.5	*Calculation*
Cost per ton Controlled — ***$/ton***	**$ 32,049**	*Calculation*

OAQPS "EPA Air Pollution Cost Manual"
Office of Air Quality Planning and Standards (OAQPS).
Section 4, Chapter 2: Selective Catalytic Reduction (June 2019)

BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - South Vacuum Heater
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
A. Equipment Design Considerations			
a. Reactor Cost (including adjustment for SCR reactor height and bypass installation)		$3,125,024	Jacobs Appraise Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)		$1,737,549	Jacobs Appraise Cost Estimate w/escalation
c. Initial Charge of Catalyst		$249,347	Jacobs Appraise Cost Estimate w/escalation
d. ID Fan Cost		$1,183,343	Jacobs Appraise Cost Estimate w/escalation
e. ID Fan Motor Cost		$313,629	Jacobs Appraise Cost Estimate w/escalation
f. Convection Section Cost		$1,505,496	Jacobs Appraise Cost Estimate w/escalation
g. Duct Work Cost		$1,816,072	Jacobs Appraise Cost Estimate w/escalation
h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit)		1.1	Jacobs
Primary Equipment Total Installed Cost		$10,923,504	*Calculation*
i. SIS Instrumentation		$1,767,575	Jacobs Appraise Cost Estimate w/escalation
j. CEMS Installation (included in SCR Cost)		$0	Jacobs
k. Local Sales tax (included in Project Contingency)		$0	Jacobs
l. Freight (included in SCR cost)		$0	Jacobs
Total Direct Capital Cost [DCC]		$12,691,079	
INDIRECT COSTS			
B. Indirect Installation			
a. General Facilities (included in Project Contingency)		$0	Jacobs
b. Engineering and Home Office Fees (included in Project Contingency)		$0	Jacobs
c. Process Contingency (included in Project Contingency)		$0	Jacobs
Total Indirect Costs [ICC]		$0	*Calculation*
C. Project Contingency (0.15 * (DCC + IIC))		$1,903,662	OAQPS
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)		$14,594,741	*Calculation*
D. Lost Production due to extended turnaround		$9,200,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]		$23,794,741	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$1,688,295**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$72,974	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (10 lb reagent/hr * 8,784 hr/yr * $0.33/lb reagent)		$28,857	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$45,125	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (122 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 8,784 hrs/yr * $0.033/kWh)		$26,451	Jacobs
Total Direct Annual Costs [DAC]		$261,007	
INDIRECT ANNUAL COSTS (IDAC)			
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$3,504	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$1,691,799	
Total Annual Cost [TAC] (DAC+IDAC)		**$1,952,806**	*Calculation*
Uncontrolled emissions	tons/year	36.8	2016 Actuals
Emissions w/SCR	tons/year	4.4	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	88.2	*Calculation*
Total Emissions Reduction	tons/year	32.5	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 60,160**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - Naphtha HDS Charge Heater
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
A. Equipment Design Considerations			
a. Reactor Cost (including adjustment for SCR reactor height and bypass installation)		$2,042,228	Jacobs Appraise Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)		$1,745,137	Jacobs Appraise Cost Estimate w/escalation
c. Initial Charge of Catalyst		$162,077	Jacobs Appraise Cost Estimate w/escalation
d. ID Fan Cost		$1,026,820	Jacobs Appraise Cost Estimate w/escalation
e. ID Fan Motor Cost		$198,996	Jacobs Appraise Cost Estimate w/escalation
f. Convection Section Cost		$1,249,904	Jacobs Appraise Cost Estimate w/escalation
g. Duct Work Cost		$1,613,564	Jacobs Appraise Cost Estimate w/escalation
h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit)		1	Jacobs
Primary Equipment Total Installed Cost		$8,038,726	*Calculation*
i. SIS Instrumentation		$1,767,575	Jacobs Appraise Cost Estimate w/escalation
j. CEMS Installation (included in SCR Cost)		$0	Jacobs
k. Local Sales tax (included in Project Contingency)		$0	Jacobs
l. Freight (included in SCR cost)		$0	Jacobs
Total Direct Capital Cost [DCC]		$9,806,300	
INDIRECT COSTS			
B. Indirect Installation			
a. General Facilities (included in Project Contingency)		$0	Jacobs
b. Engineering and Home Office Fees (included in Project Contingency)		$0	Jacobs
c. Process Contingency (included in Project Contingency)		$0	Jacobs
Total Indirect Costs [ICC]		$0	*Calculation*
C. Project Contingency (0.15 * (DCC + IIC))		$1,470,945	OAQPS
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)		$11,277,245	*Calculation*
D. Lost Production due to extended turnaround		$4,500,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]		$15,777,245	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$1,119,434**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$56,386.23	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (7 lb reagent/hr * 7,718 hr/yr * $0.33/lb reagent)		$16,742	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$29,332	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (103 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 7,718 hrs/yr * $0.033/kWh)		$19,612	Jacobs
Total Direct Annual Costs [DAC]		$209,673	
INDIRECT ANNUAL COSTS (IDAC)			
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$3,305	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$1,122,739	
Total Annual Cost [TAC] (DAC+IDAC)		**$1,332,412**	*Calculation*
Uncontrolled emissions	tons/year	20.2	2016 Actuals
Emissions w/SCR	tons/year	1.2	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	93.9	*Calculation*
Total Emissions Reduction	tons/year	19.0	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 70,260**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - Naphtha HDS Stripper Reboiler
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
A. Equipment Design Considerations			
a. Reactor Cost (including adjustment for SCR reactor height and bypass installation)		$1,518,530	Jacobs Appraise Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)		$1,726,377	Jacobs Appraise Cost Estimate w/escalation
c. Initial Charge of Catalyst		$99,084	Jacobs Appraise Cost Estimate w/escalation
d. ID Fan Cost		$702,076	Jacobs Appraise Cost Estimate w/escalation
e. ID Fan Motor Cost		$136,061	Jacobs Appraise Cost Estimate w/escalation
f. Convection Section Cost		$0	Jacobs Appraise Cost Estimate w/escalation
g. Duct Work Cost		$1,175,424	Jacobs Appraise Cost Estimate w/escalation
h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit)		1	Jacobs
Primary Equipment Total Installed Cost		$5,357,553	*Calculation*
i. SIS Instrumentation		$1,767,575	Jacobs Appraise Cost Estimate w/escalation
j. CEMS Installation (included in SCR Cost)		$0	Jacobs
k. Local Sales tax (included in Project Contingency)		$0	Jacobs
l. Freight (included in SCR cost)		$0	Jacobs
Total Direct Capital Cost [DCC]		$7,125,128	
INDIRECT COSTS			
B. Indirect Installation			
a. General Facilities (included in Project Contingency)		$0	Jacobs
b. Engineering and Home Office Fees (included in Project Contingency)		$0	Jacobs
c. Process Contingency (included in Project Contingency)		$0	Jacobs
Total Indirect Costs [ICC]		$0	*Calculation*
C. Project Contingency (0.15 * (DCC + IIC))		$1,068,769	OAQPS
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)		$8,193,897	*Calculation*
D. Lost Production due to extended turnaround		$4,500,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]		$12,693,897	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$900,663**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$40,969	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (9 lb reagent/hr * 7,718 hr/yr * $0.33/lb reagent)		$21,803	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$17,932	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (56 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 7,718 hrs/yr * $0.033/kWh)		$10,686	Jacobs
Total Direct Annual Costs [DAC]		$178,990	
INDIRECT ANNUAL COSTS (IDAC)			
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$3,120	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$903,783	
Total Annual Cost [TAC] (DAC+IDAC)		**$1,082,772**	*Calculation*
Uncontrolled emissions	tons/year	26.3	2016 Actuals
Emissions w/SCR	tons/year	1.6	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	93.9	*Calculation*
Total Emissions Reduction	tons/year	24.7	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 43,854**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - #1 Reformer Heaters
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
A. Equipment Design Considerations		
a. SCR Cost (including adjustment for SCR reactor height and bypass installation)	$60,634,889	Jacobs Select Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)	$3,400,814	Jacobs Select Cost Estimate w/escalation
c. Initial Charge of Catalyst	$997,195	Jacobs Select Cost Estimate w/escalation
d. ID Fan Cost (included in SCR Cost)	$0	Jacobs
e. ID Fan Motor Cost (included in SCR Cost)	$0	Jacobs
f. Convection Section Cost (included in SCR Cost)	$0	Jacobs
g. Duct Work Cost (included in SCR Cost)	$0	Jacobs
h. Plot Plant Installation Factor (included in SCR Cost)	1	Jacobs
Primary Equipment Total Installed Cost	$65,032,898	*Calculation*
i. SIS Instrumentation	$14,338,567	Jacobs Select Cost Estimate w/escalation
j. CEMS Installation	$4,638,116	Jacobs Select Cost Estimate w/escalation
k. Local Sales tax (included in SCR Cost)	$0	Jacobs
l. Freight (included in SCR Cost)	$0	Jacobs
Total Direct Capital Cost [DCC]	$84,009,582	
INDIRECT COSTS		
B. Indirect Installation		
a. General Facilities (included in SCR Cost)	$0	Jacobs
b. Engineering and Home Office Fees (included in SCR Cost)	$0	Jacobs
c. Process Contingency (included in SCR Cost)	$0	Jacobs
Total Indirect Costs [ICC]	$0	*Calculation*
C. Project Contingency (included in SCR Cost)	$0	Jacobs
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)	$84,009,582	*Calculation*
D. Lost Production due to extended turnaround	$10,800,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]	$94,809,582	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)	**$6,726,973**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT ANNUAL COSTS (DAC)		
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)	$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])	$420,048	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (111 lb reagent/hr * 7,768 hr/yr * $0.33/lb reagent)	$284,001	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)	$180,467	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (633 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 7,768 hrs/yr * $0.033/kWh)	$120,961	Jacobs
Total Direct Annual Costs [DAC]	$1,093,077	
INDIRECT ANNUAL COSTS (IDAC)		
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))	$7,669	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]	$6,734,641	
Total Annual Cost [TAC] (DAC+IDAC)	**$7,827,719**	*Calculation*
Uncontrolled emissions — tons/year	338.0	2016 Actuals
Emissions w/SCR — tons/year	16.9	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline — Percent	95.0	*Calculation*
Total Emissions Reduction — tons/year	321.1	*Calculation*
Cost per ton Controlled — ***$/ton***	**$ 24,378**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation -#2 Reformer
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT & INDIRECT COSTS		**COST**	**Source**
A. Lost Production due to extended turnaround		$0	Conservatively Assume no Turnaround
Total Capital Investment [TCI] - SCAQMD Capital Cost Equation, y ($/(MMBtu/hr) = 1000000*(MMBtu/hr)^-0.504 (December 12, 2019 Working Group Meeting)		$18,014,140	OAQPS with SCAQMD adjustment for refineries (http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/proposed-rule-1109-1)
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$1,278,148**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
B. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
C. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$90,071	OAQPS Chapter 2, Section 2.4.2
D. Consumables - Annual Reagent (20 lb reagent/hr * 8,493 hr/yr * $0.33/lb reagent)		$56,359	OAQPS Chapter 2, Section 2.3.13
E. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$301,331	OAQPS, Cost Calculation Spreadsheet
F. Utility costs - electricity for 187 kW * 8,493 hrs/yr * $0.033/kWh)		$49,047	OAQPS, Cost Calculation Spreadsheet for electricity usage
Total Direct Annual Costs [DAC]		$584,408	
INDIRECT ANNUAL COSTS (IDAC)			
G. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$3,709	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$1,281,856	
Total Annual Cost [TAC] (DAC+IDAC)		**$1,866,264**	*Calculation*
Uncontrolled emissions	tons/year	67.2	2016 Actuals
Emissions w/SCR	tons/year	3.4	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	94.9	*Calculation*
Total Emissions Reduction	tons/year	63.7	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 29,289**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - Hydrocracker R-4 Heater
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
A. Equipment Design Considerations		
a. Reactor Cost (including adjustment for SCR reactor height and bypass installation)	$1,183,946	Jacobs Appraise Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)	$1,715,996	Jacobs Appraise Cost Estimate w/escalation
c. Initial Charge of Catalyst	$64,218	Jacobs Appraise Cost Estimate w/escalation
d. ID Fan Cost	$606,218	Jacobs Appraise Cost Estimate w/escalation
e. ID Fan Motor Cost	$117,484	Jacobs Appraise Cost Estimate w/escalation
f. Convection Section Cost	$0	Jacobs Appraise Cost Estimate w/escalation
g. Duct Work Cost	$1,040,076	Jacobs Appraise Cost Estimate w/escalation
h. Plot Plant Installation Factor (addressed ease of installation - new or retrofit)	1	Jacobs
Primary Equipment Total Installed Cost	$4,727,938	*Calculation*
i. SIS Instrumentation (already partially installed)	$707,030	Jacobs Appraise Cost Estimate w/escalation
j. CEMS Installation (included in SCR Cost)	$0	Jacobs
k. Local Sales tax (included in Project Contingency)	$0	Jacobs
l. Freight (included in SCR cost)	$0	Jacobs
Total Direct Capital Cost [DCC]	$5,434,968	
INDIRECT COSTS		
B. Indirect Installation		
a. General Facilities (included in Project Contingency)	$0	Jacobs
b. Engineering and Home Office Fees (included in Project Contingency)	$0	Jacobs
c. Process Contingency (included in Project Contingency)	$0	Jacobs
Total Indirect Costs [ICC]	$0	*Calculation*
C. Project Contingency (0.15 * (DCC + IIC))	$815,245	OAQPS
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)	$6,250,214	*Calculation*
D. Lost Production due to extended turnaround	$0	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]	$6,250,214	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)	**$443,468**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT ANNUAL COSTS (DAC)		
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)	$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])	$31,251	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (9 lb reagent/hr * 7,572 hr/yr * $0.33/lb reagent)	$23,222	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)	$11,622	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (43 HP (total increase from current ID fan + vaporization) * 0.7457 kW/HP * 7,572 hrs/yr * $0.033/kWh)	$7,973	Jacobs
Total Direct Annual Costs [DAC]	$161,668	
INDIRECT ANNUAL COSTS (IDAC)		
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))	$3,003	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]	$446,471	
Total Annual Cost [TAC] (DAC+IDAC)	**$608,139**	*Calculation*
Uncontrolled emissions — tons/year	27.6	2016 Actuals
Emissions w/SCR — tons/year	1.4	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline — Percent	95.0	*Calculation*
Total Emissions Reduction — tons/year	26.2	*Calculation*
Cost per ton Controlled — ***$/ton***	**$ 23,194**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
ULNB Cost Effectiveness Calculation - #1 H2 Plant (North and South Furnaces)
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
A. Equipment Design Considerations			
a. Burner Cost & Installation (both furnaces, 384 burners for each furnace)		$12,160,915	Jacobs Select Cost Estimate w/escalation
b. Forced Draft Fan with Motor Installed Cost (included in Burner Cost)		$0	Jacobs
c. Installed Fuel Filter Skid (included in Burner Cost)		$0	Jacobs
d. Duct Work Cost (included in Burner Cost)		$0	Jacobs
e. SIS Instrumentation		$11,934,666	Jacobs Select Cost Estimate w/escalation
f. Instrumentation (included in Burner Cost)		$0	Jacobs
g. Local sales tax (included in Burner Cost)		$0	Jacobs
h. Freight (included in Burner Cost)		$0	Jacobs
Primary Equipment Installed Cost		$24,095,581	*Calculation*
i. CEMS Installation (both furnaces)		$9,445,920	Jacobs Select Cost Estimate w/escalation
j. Local Sales tax (included in Burner Cost)		$0	Jacobs
k. Freight (included in Burner Cost)		$0	Jacobs
Total Direct Capital Cost [DCC]		$33,541,501	
INDIRECT COSTS			
B. Indirect Installation			
a. General Facilities (included in Burner Cost)		$0	Jacobs
b. Engineering and Home Office Fees (included in Burner Cost)		$0	Jacobs
c. Process Contingency (included in Burner Cost)		$0	Jacobs
Total Indirect Costs [ICC]		$0	*Calculation*
C. Project Contingency (Conservatively Assume No Contingency)		$0	
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)		$33,541,501	*Calculation*
D. Lost Production due to extended turnaround		$12,500,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]		$46,041,501	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$3,266,758**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
E. Operating and Supervisory Labor (assumed none for LNB)		$0	
F. Maintenance Labor and Costs (assumed none for LNB)		$0	
G. CEMS Operations (assumed none for LNB)		$0	
H. Utility costs (assumed none for LNB)		$0	
Total Direct Annual Costs [DAC]		$0	
INDIRECT ANNUAL COSTS (IDAC)			
I. Administrative Charges (assumed none for LNB)		$0	
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$3,266,758	*Calculation*
Total Annual Cost [TAC] (DAC+IDAC)		**$3,266,758**	*Calculation*
Uncontrolled emissions	tons/year	150.6	2016 Actuals (both furnaces)
Emissions w/LNB	tons/year	84.5	LNB Vendor Guarantee (0.055 lb NOx/MMBtu)
Reduction from baseline	Percent	43.9	*Calculation*
Total Emissions Reduction	tons/year	66.1	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 49,432**	*Calculation*

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BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - #1 H2 Plant (North and South Furnaces)
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
A. Equipment Design Considerations			
a. SCR Cost (including adjustment for SCR reactor height and bypass installation)		$70,702,995	Jacobs Select Cost Estimate w/escalation
b. Ammonia Delivery System (includes adjustment for ammonia flow rate)		$6,801,628	Jacobs Select Cost Estimate w/escalation
c. Initial Charge of Catalyst		$361,999	Jacobs Select Cost Estimate w/escalation
d. ID Fan Cost (included in SCR Cost)		$0	Jacobs
e. ID Fan Motor Cost (included in SCR Cost)		$0	Jacobs
f. Convection Section Cost (included in SCR Cost)		$0	Jacobs
g. Duct Work Cost (included in SCR Cost)		$0	Jacobs
h. Plot Plant Installation Factor (included in SCR Cost)		1	Jacobs
Primary Equipment Total Installed Cost		$77,866,623	*Calculation*
i. SIS Instrumentation		$12,387,165	Jacobs Select Cost Estimate w/escalation
j. CEMS Installation		$5,571,396	Jacobs Select Cost Estimate w/escalation
k. Local Sales tax (included in SCR Cost)		$0	Jacobs
l. Freight (included in SCR Cost)		$0	Jacobs
Total Direct Capital Cost [DCC]		$95,825,183	
INDIRECT COSTS			
B. Indirect Installation			
a. General Facilities (included in SCR Cost)		$0	Jacobs
b. Engineering and Home Office Fees (included in SCR Cost)		$0	Jacobs
c. Process Contingency (included in SCR Cost)		$0	Jacobs
Total Indirect Costs [ICC]		$0	*Calculation*
C. Project Contingency (included in SCR Cost)		$0	Jacobs
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)		$95,825,183	*Calculation*
D. Lost Production due to extended turnaround		$47,500,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]		$143,325,183	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$10,169,274**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$479,126	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (43 lb reagent/hr * 8,760 hr/yr * $0.33/lb reagent)		$125,031	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$65,513	Jacobs SELECT Cost Estimate
I. Utility costs - electricity for fan & ammonia vaporization (480 HP (total increase from current ID fans + vaporization) * 0.7457 kW/HP * 8,760 hrs/yr * $0.033/kWh)		$103,461	Jacobs
Total Direct Annual Costs [DAC]		$860,731	
INDIRECT ANNUAL COSTS (IDAC)			
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$8,378	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$10,177,651	
Total Annual Cost [TAC] (DAC+IDAC)		**$11,038,382**	*Calculation*
Uncontrolled emissions	tons/year	150.6	2016 Actuals (both furnaces)
Emissions w/SCR	tons/year	9.2	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	93.9	*Calculation*
Total Emissions Reduction	tons/year	141.4	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 78,082**	*Calculation*

OAQPS "EPA Air Pollution Cost Manual"
Office of Air Quality Planning and Standards (OAQPS).
Section 4, Chapter 2: Selective Catalytic Reduction (June 2019)

BP 2020 Regional Haze 4-Factor Analysis
ULNB with SCR Cost Effectiveness Calculation - #1 H2 Plant (North and South Furnaces)
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
A. Equipment Design Considerations		
a. Burner Cost & Installation (both furnaces, 384 burners for each furnace)	$12,160,915	Jacobs Select Cost Estimate w/escalation
b. SCR Cost (including adjustment for SCR reactor height and bypass installation)	$70,702,995	Jacobs Select Cost Estimate w/escalation
c. Ammonia Delivery System (includes adjustment for ammonia flow rate)	$6,801,628	Jacobs Select Cost Estimate w/escalation
d. Initial Charge of Catalyst	$333,718	Jacobs Select Cost Estimate w/escalation
e. ID Fan Cost (included in SCR Cost)	$0	Jacobs
f. ID Fan Motor Cost (included in SCR Cost)	$0	Jacobs
g. Convection Section Cost (included in SCR Cost)	$0	Jacobs
h. Duct Work Cost (included in SCR Cost)	$0	Jacobs
i. Plot Plant Installation Factor (included in SCR Cost)	1	Jacobs
Primary Equipment Total Installed Cost	$89,999,257	*Calculation*
j. SIS Instrumentation	$12,387,165	Jacobs Select Cost Estimate w/escalation
k. CEMS Installation	$5,571,396	Jacobs Select Cost Estimate w/escalation
l. Local Sales tax (included in SCR Cost)	$0	Jacobs
m. Freight (included in SCR Cost)	$0	Jacobs
Total Direct Capital Cost [DCC]	$107,957,817	
INDIRECT COSTS		
B. Indirect Installation		
a. General Facilities (included in SCR Cost)	$0	Jacobs
b. Engineering and Home Office Fees (included in SCR Cost)	$0	Jacobs
c. Process Contingency (included in SCR Cost)	$0	Jacobs
Total Indirect Costs [ICC]	$0	*Calculation*
C. Project Contingency (included in SCR Cost)	$0	Jacobs
D. Total Plant Cost [TPC] (DCC+ICC+Project Contingency)	$107,957,817	*Calculation*
D. Lost Production due to extended turnaround	$47,500,000	Jacobs & BP Turnaround Team
Total Capital Investment [TCI]	$155,457,817	*Calculation*
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)	**$11,030,114**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT ANNUAL COSTS (DAC)		
E. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)	$87,600	OAQPS Chapter 2, Section 2.4.2
F. Maintenance Labor and Costs (0.005*[TCI - Lost Production])	$539,789	OAQPS Chapter 2, Section 2.4.2
G. Consumables - Annual Reagent (23 lb reagent/hr * 8,760 hr/yr * $0.33/lb reagent)	$66,588	OAQPS Chapter 2, Section 2.3.13
H. Consumables - Catalyst (annualized over 5 years @ 5% interest)	$60,395	Jacobs
I. Utility costs - electricity for fan & ammonia vaporization (480 HP (total increase from current ID fans + vaporization) * 0.7457 kW/HP * 8,760 hrs/yr * $0.033/kWh)	$103,461	Jacobs
Total Direct Annual Costs [DAC]	$857,832	
INDIRECT ANNUAL COSTS (IDAC)		
J. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))	$9,105	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]	$11,039,220	
Total Annual Cost [TAC] (DAC+IDAC)	**$11,897,052**	*Calculation*
Uncontrolled emissions — tons/year	150.6	2016 Actuals (both furnaces)
Emissions w/SCR — tons/year	9.2	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline — Percent	93.9	*Calculation*
Total Emissions Reduction — tons/year	141.4	*Calculation*
Cost per ton Controlled — ***$/ton***	**$ 84,156**	*Calculation*

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Office of Air Quality Planning and Standards (OAQPS).
Section 4, Chapter 2: Selective Catalytic Reduction (June 2019)

BP 2020 Regional Haze 4-Factor Analysis
SCR Cost Effectiveness Calculation - Boiler 5
Cherry Point Refinery, Whatcom County, Washington

CAPITAL COSTS			
DIRECT & INDIRECT COSTS		**COST**	**Source**
A. Lost Production due to extended turnaround		$0	Conservatively Assume no Turnaround
Total Capital Investment [TCI] - SCAQMD Capital Cost Equation, y ($/(MMBtu/hr) = 1000000*(MMBtu/hr)^-0.504 (December 12, 2019 Working Group Meeting)		$18,608,599	OAQPS with SCAQMD adjustment for refineries (http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/proposed-rule-1109-1)
Total Annualized Capital Costs [TACC] (25 years @ 5.00 % interest)		**$1,320,326**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT ANNUAL COSTS (DAC)			
B. Operating and Supervisory Labor (4 hrs/day * $60/hr * 365 day/yr)		$87,600	OAQPS Chapter 2, Section 2.4.2
C. Maintenance Labor and Costs (0.005*[TCI - Lost Production])		$93,043.00	OAQPS Chapter 2, Section 2.4.2
D. Consumables - Annual Reagent (4 lb reagent/hr * 8,592 hr/yr * $0.33/lb reagent)		$11,499	OAQPS Chapter 2, Section 2.3.13
E. Consumables - Catalyst (annualized over 5 years @ 5% interest)		$83,683	OAQPS, Cost Calculation Spreadsheet
F. Utility costs - electricity for 187 kW * 8,592 hrs/yr * $0.033/kWh)		$53,021	OAQPS, Cost Calculation Spreadsheet for electricity usage
Total Direct Annual Costs [DAC]		$328,846	
INDIRECT ANNUAL COSTS (IDAC)			
G. Administrative Charges (0.03*(Operating Labor + 0.4*Maintenance))		$3,745	OAQPS Chapter 2, Equation 2.69
Total Indirect Annual Costs (TACC + ADMIN) [IDAC]		$1,324,070	
Total Annual Cost [TAC] (DAC+IDAC)		**$1,652,916**	*Calculation*
Uncontrolled emissions	tons/year	16.2	2016 Actuals
Emissions w/SCR	tons/year	3.2	control to 95% or 5 ppmv, whichever is greater
Reduction from baseline	Percent	80.3	*Calculation*
Total Emissions Reduction	tons/year	13.0	*Calculation*
Cost per ton Controlled	***$/ton***	**$ 126,958**	*Calculation*

OAQPS "EPA Air Pollution Cost Manual"
Office of Air Quality Planning and Standards (OAQPS).
Section 4, Chapter 2: Selective Catalytic Reduction (June 2019)

John L. Andersen

HSE Manager
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Lacey, WA 98503

June 29, 2020
HSE450.015.Regional Haze

Re: Phillips 66 Ferndale Refinery Four Factor Analysis

Dear Mr. Hanlon-Meyer,

Attached please find the Phillips 66 Ferndale Refinery Four Factor Analysis, to be incorporated into Ecology's Regional Haze effort. The Phillips 66 Ferndale Refinery Four Factor Analysis has been revised to incorporate the costs of low-NOx burner (LNB) retrofits for heaters and boilers. As you recall, completion of this analysis was delayed by Covid-19.

In conjunction with the updates to the four-factor analysis for LNB cost evaluations, it is worth noting that the status of existing emission controls for the units evaluated in this report have adjusted slightly. Through P66's detailed review of the existing burners for the heaters and boilers, as well as the evaluations conducted by the burner vendors, Phillips 66 concludes that the burners currently in operation for the alkylation heater (17F-1) and the DHT heater (33F-1) are considered low-NOx burners. Because current emissions from these heaters are consistent with low-NOx burners currently available for retrofit, an LNB cost-effectiveness evaluation was not conducted for these heaters.

Please feel free to contact Erin Strang at (360) 384-8217 or erin.t.strang@p66.com with any questions or concerns.

Sincerely,

John L. Andersen

John L. Andersen

Enclosure: Phillips 66 Ferndale Refinery Four Factor Analysis

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Phillips 66 > Ferndale, WA Refinery

Prepared By:

Aaron Day – Principal Consultant
Melissa Hillman – Principal Consultant
Sam Najmolhoda – Associate Consultant

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June 2020

Project 194801.0113

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1. EXECUTIVE SUMMARY

On November 27, 2019, Ecology sent a letter to P66 requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" P66's Ferndale, WA refinery.[1] P66 understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the P66 Ferndale refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, P66 understands that Ecology will only move forward with requiring emission reductions from the P66 Ferndale refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost-effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus the control cost development on low-NO_X burners (LNB) and selective catalytic reduction (SCR). For NO_X emissions, a complete four-factor analysis is provided for SCR at this time. For completeness, a qualitative discussion of each of the remaining pollutants is also included in this analysis.

P66 concludes that SCR is likely technically feasible for the units evaluated in this report, although further engineering analysis would be required to conclusively confirm SCR's feasibility for each unit in question. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

In the case of LNB, there are several boilers and heaters that already have LNB installed. While retrofitting heaters and boilers that do not currently have LNB is technically feasible, cost calculations indicate the control technology is not cost-effective for these units for the regional haze program.

P66 concludes that the existing emissions reduction method of good combustion practices is consistent with the specified technology in recent determinations for units of similar size under more stringent regulatory programs (e.g., the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.[2]

[1] Letter from Ecology to P66 dated November 27, 2019.

[2] Search results from the EPA's RACT/BACT/LAER Clearinghouse database are provided in Appendix A of this report.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

(A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On November 27, 2019, Ecology sent a letter to P66 requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" P66's Ferndale, WA refinery.[3] P66 understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the P66 Ferndale refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, P66 understands that Ecology will only move forward with requiring emission reductions from the P66 Ferndale refinery if the emission reductions are both cost-effective and needed to show reasonable progress. Control options are only relevant for the Regional Haze Rule if they result in a meaningful reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

[3] Letter from Chris Hanlon-Meyer, Ecology to Erin Strang, P66, dated November 27, 2019.

In the November 27 request letter, Ecology additionally requested that P66 "include all information regarding activities that have the potential to reduce the cost of compliance." As a standard practice, the refinery evaluates projects undertaken at the refinery for the potential to reduce costs through energy efficient design and timing of maintenance.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA) dated March 9, 2020, Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus on control cost development for low-NO_X burners and selective catalytic reduction (SCR). For NO_X emissions, a complete four-factor analysis is provided for SCR and low-NO_X burners. A qualitative discussion of each of the remaining pollutants is also included in this analysis.

The information presented in this report for NO_X controls considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the units

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[4] for conducting a review of Best Available Retrofit Technology (BART) for a unit. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for NO_X can be found in Section 6 of this report. A qualitative review of the other pollutants included in the initial four-factor analysis request (SO_2, PM_{10}, NH_3, and H_2SO_4) is provided in Section 5. Section 4 of this report includes information on the P66's existing/baseline emissions for the emission units relevant to Ecology's regional haze efforts.

[4] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

3. SOURCE DESCRIPTION

The Ferndale Refinery is located at 3901 Unick Road in Ferndale, Whatcom County, Washington. The refinery is located on the coastline adjacent to the Strait of Georgia in a rural setting zoned for heavy industrial use. The area surrounding the refinery is designated in attainment with all National Ambient Air Quality Standards.

The Ferndale Refinery is a petroleum refinery that uses crude oil as a feedstock that is processed into a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG) and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline. The crude oil throughput capacity of the refinery is approximately 108,000 barrels per day.

The refining process at the Ferndale Refinery is described as follows. Crude oil enters the refining process at the Crude Distillation Unit where hydrocarbon is separated into light and heavy fractions based on their boiling point. These fractions or “cuts” are routed to other process units where they undergo catalytic cracking, catalytic reforming, isomerization, alkylation, or treatment. Treating systems are used to remove or reduce fuel impurities such as sulfur and benzene. Sulfur is recovered in the Sulfur Recovery Unit (SRU) as elemental sulfur. Some of the lighter hydrocarbons are flashed off as gases during processing and used as fuel in the refinery’s fuel gas systems. The refinery has an oily wastewater system that routes hydrocarbon-bearing wastewater to the refinery’s wastewater treatment system prior to discharge into the Strait of Georgia. In final processing, fuel components are blended into finished products and stored. Finished products are shipped to market via ship, barge, pipeline, railcar, or truck.

It is worth noting that the Ferndale refinery barely exceeded the Q/d screening threshold used by Ecology to determine which facilities are candidates for the Reasonable Available Control Technology (RACT)/four-factor analysis. With a cutoff of 10 for the Q/d ratio (the ratio of facility emissions over the distance to the nearest Class I area), P66 had a Q/d of only 10.88. This is due in part to the improvements P66 has made to the Ferndale refinery during the current planning period to provide greater levels of emission control for NO_X. These retrofits were unrelated to Regional Haze but represent approximately a 20% reduction in NO_X emissions from the 2008-2009 average NO_X emissions to the 2014-2018 average NO_X emissions, which serves as the baseline emissions period for this regional haze four-factor analysis.

In the time period since the first planning period of the regional haze program, P66 has made the following improvements to the facility, reducing the emission of visibility impairing pollutants:

- The Fluid Catalytic Cracking Unit (FCCU) Vacuum Heater (Unit 4F-2) was retrofitted with SCR in 2008.
  - This retrofit resulted in an average annual emission decrease of 102.9 tons per year of NO_X.
- The FCCU CO Boiler was retrofitted with Enhanced Selective Non-Catalytic Reduction (ESNCR) in 2010.
  - This retrofit resulted in an average annual emission decrease of 21.0 tons per year of NO_X.
- A redundant Flare Gas Recovery Compressor was added in 2011.
  - This retrofit resulted in an average annual emission decrease of 27.7 tons per year of NO_X.

Figure 3-1. Aerial View of the Ferndale Refinery

Per the four-factor analysis request from Ecology, the following units require completion of a four factor analysis if they have not been retrofitted since 2005:

- Fluid Catalytic Cracking Units (FCCUs)
- Boilers greater than 40 MMBtu/hr
- Heaters greater than 40 MMBtu/hr

Considering these source types and the timeline of projects at the P66 refinery, the following units require a four-factor analysis.

Table 3-1. Summary of Units Requiring Four-Factor Analyses at the Phillips 66 Refinery

Process Unit	Unit ID	Unit Description	Maximum Heat Input (MMBtu/hr)	Date Constructed	Date Retrofitted	Control Device(s) Currently Installed	Pollutant(s) Controlled
Crude	1F-1	Crude Heater	191	1953	N/A	--	--
	1F-1A	Crude Heater	98	1972	N/A	--	--
Alky	17F-1	Alky Heater	106	1965	N/A	Low-NO_X Burners	--
Reformer	18F-1	Pretreater Heater	41	1972	N/A	--	--
	18F-21	Reformer Heater	47	1972	N/A	--	--
	18F-22	Reformer Heater	47	1972	N/A	--	--
	18F-23	Reformer Heater	47	1972	N/A	--	--
	18F-24	Reformer Heater	47	1972	N/A	--	--
Boilers	22F-1C	#1 Boiler	162	1996	N/A	Flue Gas Recirculation and Low-NO_X Burners	NO_X
	22F-1A	#2 Boiler	91	1953	N/A	--	--
	22F-1B	#3 Boiler	108	1953	N/A	--	--
DHT	33F-1	DHT Heater	48	1992	2001	Low-NO_X Burners	--
S-Zorb	38F-100	S-Zorb Heater	46	2003	N/A	Low-NO_X Burners	--

Baseline emissions from the units listed in Section 3 of this report are calculated based on a mass balance on the fuel combusted. Emissions used for this four-factor analysis are consistent with those submitted for the Washington Emissions Inventory Reporting System (WEIRS). To develop an emissions baseline, based on recent data for the facility and representative of anticipated actual emissions for the near future, WEIRS emissions data from the period of 2014-2018 was analyzed. For the purposes of this analysis, the average of the 5 years of emissions is used as the baseline against which potential emissions reductions and the associated control costs are compared. Emissions from the applicable units at the P66 refinery are provided in Table 4-1 and Table 4-2 below.

Table 4-1. Baseline Emissions Summary – All Applicable Units

Pollutant	Baseline Emissions (tons)
NO_X	422.71
SO_2	7.60
PM_{10}	8.15
NH_3	0.00
H_2SO_4	0.67

Table 4-2. Baseline Emissions Summary - Individual Units

Emission Unit	Annual Emissions (tons)				
	PM_{10}	SO_2	NO_X	H_2SO_4	NH_3
Crude Heater 1F-1	1.89	2.13	176.74	1.14E-01	0.00
#2 Crude Heater 1F-1A	0.89	1.00	41.74	5.82E-02	0.00
Alkylation Heater 17F-1	0.45	0.51	21.20	2.29E-03	0.00
#3 Pretreater Heater 18F-1	0.22	0.12	10.10	6.34E-03	0.00
#3 Reformer Heater 18F-21	0.89	0.50	41.49	1.20E-02	0.00
18F-22 (Included with Above)					
#3 Reformer Heater 18F-23	0.89	0.50	41.49	1.18E-02	0.00
18F-24 (Included with Above)					
No. 1 Boiler 22F-1C	0.82	0.91	9.30	1.63E-01	0.00
No. 2 Boiler 22F-1A	0.69	0.76	32.37	1.34E-01	0.00
No. 3 Boiler 22F-1B	0.88	0.99	41.24	1.57E-01	0.00
DHT Heater 33F-1	0.24	0.13	4.30	1.24E-02	0.00
S-Zorb Heater 38F-100(CNG)	0.27	0.05	2.75	1.51E-03	0.00

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

Per Ecology's direction, the four-factor analysis with complete control cost evaluations will be conducted only for SCR and low-NO_X burners.

The baseline NO_X emission rates that are used in this four-factor analysis are summarized in Table 4-1 and Table 4-2. The basis of the emission rates is provided in Section 4 of this report.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

In order to minimize NO_X emissions from a combustion unit, controls can take the form of either combustion or post-combustion methods. Low-NO_X burners work to limit NO_X formation during combustion, using various methods to reduce peak flame temperature and increase flame length. SCR addresses NO_X emissions post-combustion, using catalyst and reagent to convert NO_X to elemental nitrogen before emissions leave the stack. Both controls are explained in more detail below. Good combustion practices are also described, as they represent the current emissions reduction method for several of the burners and heaters at the refinery.

5.1.1. Combustion Controls

5.1.1.1. Low-NO_X (LNB)

Low -NO_X burners (LNB) are perhaps the most widely used NO_X control devices for refinery process heaters today. Different burner manufactures use different burner designs to achieve low NO_X emissions, but all designs essentially implement two fundamental tactics - low excess air and staged combustion. Low excess air decreases the total amount of nitrogen present at the burner, thereby decreasing the resulting thermal NO_X formation. Staged combustion burns fuel in two or more steps. The primary combustion zone is fuel-rich, and the secondary zones are fuel-lean. Using these tactics, LNBs inhibit thermal NO_X formation by controlling the flame temperature and the fuel/air mixture within the flame burner zone.

5.1.1.2. Good Combustion Practices

NO_X emissions can be controlled by maintaining various operational combustion parameters. These operational methods can include staged fuel combustion, staged air combustion, and low excess air combustion. The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. This is an appropriate control option for small heaters in which emissions are considered to be de minimis. Good combustion practices are the selected control option for several emission units found in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, which provides control units required as part of programs more stringent in requirement than the regional haze program, including consent decrees and the Prevention of Significant Deterioration Best Available Control Technology (PSD BACT) program. The detailed RBLC database search results are included in Appendix A of this report.

5.1.2. Post Combustion Controls

5.1.2.1. Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$

$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[5] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1. Combustion Controls

5.2.1.1. Low-NO_X Burners

Burner design, operating conditions, and surrounding equipment can heavily influence technical feasibility for burner retrofits. In the case of Boiler #1 (Unit 22F-1C), a LNB is already used, with flue gas recirculation

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[5] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

used as well. The Alkylation Heater (Unit 17F-1), the DHT Heater (33F-1), and the S-Zorb Heater (38F-100) also currently use burners classified as LNB by burner vendors.

This four-factor analysis does not rule out LNBs on the basis of technical feasibility for the remaining evaluated units. Information obtained from vendors indicates that LNBs are technically feasible for those units where LNBs are not currently installed and operating.

5.2.1.2. Good Combustion Practices

Good combustion practices are currently employed for all burners and heaters, and are therefore considered technically feasible for the facility. Good combustion practices are considered the baseline emissions reduction method for this analysis, and all emissions reductions estimates use this control as a baseline.

5.2.2. Post Combustion Controls

5.2.2.1. Selective Catalytic Reduction

SCR is a widely accepted emissions control technology for heaters and burners in the industry. While specific circumstances can result in SCR implementation challenges or even infeasibility for a given unit, the technology more broadly is considered technically feasible. However, P66 has not undertaken a detailed engineering review of SCR's technical feasibility for the units at the Ferndale refinery.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

The effectiveness of LNBs varies from unit to unit – specific evaluations are necessary to determine whether a burner retrofit is technically feasible, as well as what level of control will be achieved. The efficiencies are summarized in table 5-1, below. Detailed cost calculations are provided in Appendix B of this report.

Table 5-1. Summary of Emissions Reduction Effectiveness

Emissions Reduction Method	Control Efficiency
Selective Catalytic Reduction (SCR) [1]	90%
Low-NO_X Burners (LNB) [2]	15-34%
Good Combustion Practices	Baseline

[1] SCR control efficiency, for the purposes of the cost calculations and four-factor analysis, is assumed to be 90% based on data provided in the EPA Control Technology Fact Sheet for SCR.
https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
The use of this control efficiency is a conservative approximation, and testing would be required on a unit-by-unit basis to determine what level of control is attainable, particularly given concerns of ammonia slip that can result in impacts counter to the goals of the regional haze program.

[2] LNB control efficiency varies from unit to unit and is based on vendor estimates of NO_X control levels for burner retrofits. These control levels are estimates, and additional testing would be required to determine actual NO_X emission levels should a retrofit be required.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

5.4.1.1. Selective Catalytic Reduction (SCR) Cost Calculations

SCR cost calculations are developed using a vendor quote and actual project costs for SCR on the Vacuum Heater for the Fluid Catalytic Cracking Unit (FCCU). Where applicable, cost calculations are drawn from the EPA Control Cost Manual.

Costs for each unit are scaled by rated heat input, and costs are converted to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[6]

SCR cost calculations are summarized in Table 5-2. Detailed cost calculations are included in Appendix B.

5.4.1.2. Low-NO_X Burner Cost Calculations

LNB cost calculations are developed using estimates from Tulsa Heaters and John Zink. Where necessary, additional installation and indirect costs are calculated using the EPA Control Cost Manual. LNB cost calculations are summarized in Table 5-2 as well, with detailed cost calculations provided in Appendix B.

[6] Jenkins, S. "2019 Chemical Engineering Plant Cost Index Annual Average." 20 March 2020. https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

Table 5-2. Summary of Cost Calculations for SCR and LNB

Emission Unit	Baseline Emission Rate	SCR			LNB		
		Total Annualized Cost ($/year)	Total Pollutant Removed (ton/year)	Cost Effectiveness ($/ton)	Total Annualized Cost ($/year)	Total Pollutant Removed (ton/year)	Cost Effectiveness ($/ton)
Crude Heater 1F-1	176.74	$1,944,651	159.07	$12,225	$382,016	26.77	$14,271
#2 Crude Heater 1F-1A	41.74	$1,506,809	37.57	$40,111	$214,872	10.94	$19,636
Alkylation Heater 17F-1	21.20	$1,553,311	19.08	$81,410	--	--	--
#3 Pretreater Heater 18F-1	10.10	$1,160,157	9.09	$127,630	$121,694	3.39	$35,848
#3 Reformer Heater 18F-21	41.49	$1,202,631	37.34	$32,207	$87,093	5.44	$15,998
18F-22 (Included with Above for SCR) [1]	--	--	--	--	$87,093	5.44	$15,998
#3 Reformer Heater 18F-23	41.49	$1,202,645	37.34	$32,207	$87,093	5.44	$15,998
18F-24 (Included with Above for SCR) [1]	--	--	--	--	$87,093	5.44	$15,998
No. 1 Boiler 22F-1C	9.30	$1,875,755	8.37	$224,104	--	--	--
No. 2 Boiler 22F-1A [2]	32.37	$1,487,733	29.13	$51,067	$81,829	8.49	$9,643
No. 3 Boiler 22F-1B [2]	41.24	$1,582,416	37.12	$42,634	$81,829	10.81	$7,572
DHT Heater 33F-1	4.30	$1,208,922	3.87	$312,383	--	--	--
S-Zorb Heater 38F-100(CNG)	2.75	$1,186,695	2.48	$479,473	--	--	--

[1] In the case of units with a shared stack, it is assumed that for the purposes of determining LNB costs that each unit is responsible for an equal portion of the total emissions originating from the stack.

[2] In addition to the costs provided in this table, the boiler control system would need to be upgraded to provide a better degree of control of combustion in the boiler for low-NO_X burners to operate effectively. The costs for the boiler control system have not been evaluated at this time, but are expected to be substantial..

5.4.2. Timing for Compliance

P66 believes that reasonable progress compliant controls (good combustion practices) are already in place. Any changes to heaters or boilers at the refinery would need to be incorporated into the schedule of a future refinery turnaround. Refinery turnarounds are infrequent and complex undertakings that require several years of advance planning. However, if Ecology determines that one of the NO_X reduction options analyzed in this report is necessary to achieve reasonable progress, control system upgrades could be incorporated into a future refinery turnaround.

5.4.3. Energy Impacts and Non-Air Quality Impacts

The cost of energy required to operate SCR has been included in the cost analyses found in Appendix B. To operate the SCR, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Reheating the flue gas, as necessary, for SCR application would also require substantial natural gas usage with an associated increase in direct emissions. The use of NO_X reduction methods that incorporate ammonia injection like SCR leads to increased potential for ammonia slip emissions. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills.

P66 does not anticipate any substantial energy or non-air quality impacts resulting from the potential retrofitting of boilers and heaters for LNB.

5.4.4. Remaining Useful Life

The remaining useful life for all units evaluated in this analysis is at least 20 years, and thus is not considered to have an impact on the feasibility or applicability of either emissions reduction option being considered.

5.5. NO_X CONCLUSION

P66 concludes that SCR is likely to be technically feasible for the units evaluated in this report. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

LNB cost calculations indicate that, while the annual cost would be lower than those of an SCR retrofit, the control would not be cost effective for this refinery. P66 concludes that while technically feasible, LNB does not represent an appropriate control for the purposes of the regional haze program, as the retrofit is not cost-effective for NO_X control.

P66 notes that the existing emissions reduction method of good combustion practice is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.

6. PM_{10}, SO_2, NH_3, AND H_2SO_4 EVALUATION

Per Ecology's direction, the only emissions controls being evaluated for a complete four-factor analysis are SCR and low-NO_X burners for NO_X emissions control. Given that the initial four-factor analysis request in November 2019 included PM_{10}, SO_2, NH_3, and H_2SO_4, the following section is provided for completeness. This section of the report provides a qualitative assessment of the four additional pollutants other than NO_X, with conclusions consistent with Ecology's direction that a detailed analysis of these pollutants is not necessary for this submittal.

The baseline emission rates for PM_{10}, SO_2, NH_3, and H_2SO_4 are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

The U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and historic BACT reports for the facility were searched to identify possible control technologies that could be used to reduce PM_{10}, SO_2, NH_3, and H_2SO_4 emissions from applicable units for regional haze at the Ferndale refinery. To ensure all potentially relevant control methodologies were considered, the search was conducted both for combustion units less than 100 MMBtu/hr of heat input and combustion units with a heat input between 100 and 250 MMBtu/hr.

In the case of PM_{10} and H_2SO_4, the RBLC results include only good combustion practices for emissions controls. This is consistent with current practices at the Ferndale refinery, and P66 concludes that no additional controls or emission reduction measures are necessary for the Ferndale refinery.

For SO_2 entries in the RBLC database, the control technologies likewise included combustion practices, with the use of low-sulfur fuels for combustion also included. CEMS are currently used to monitor inlet fuel sulfur content to ensure compliance with the refinery fuel gas sulfur requirements of NSPS Subpart J. Good combustion practices and the use of low-sulfur fuels are consistent with current practices at the Ferndale refinery, and no additional emissions reductions options are required to maintain practices consistent with those found in the RBLC database.

Finally, for NH_3 there are currently no appreciable NH_3 emissions from the units currently evaluated for the four-factor analysis. Should emissions controls be installed that involve the use of ammonia, then there is the potential for ammonia slip to result; however, there are currently no ammonia-using controls on any of the units covered in this report. Therefore, no additional emission reduction measures are appropriate at this time.

No additional control measures were identified as appropriate for the process heaters and boilers applicable to regional haze at this facility. Therefore, no additional controls or emission reduction options are evaluated for PM_{10}, SO_2, NH_3, and H_2SO_4 in this analysis.

APPENDIX A : RBLC SEARCH RESULTS

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oil	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx annual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx anual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Table B-1. SCR Cost Calculation Summary

Emission Unit ID	SCR Cost Effectiveness ($/ton removed)	Total Annualized Cost ($/year)	Total Pollutant Removed (tons)
Crude Heater 1F-1	$12,225	$1,944,651	159.07
#2 Crude Heater 1F-1A	$40,111	$1,506,809	37.57
Alkylation Heater 17F-1	$81,410	$1,553,311	19.08
#3 Pretreater Heater 18F-1	$127,630	$1,160,157	9.09
#3 Reformer Heater 18F-21	$32,207	$1,202,631	37.34
18F-22	Included Above		
#3 Reformer Heater 18F-23	$32,207	$1,202,645	37.34
18F-24	Included Above		
No. 1 Boiler 22F-1C	$224,104	$1,875,755	8.37
No. 2 Boiler 22F-1A	$51,067	$1,487,733	29.13
No. 3 Boiler 22F-1B	$42,634	$1,582,416	37.12
DHT Heater 33F-1	$312,383	$1,208,922	3.87
Szorb Heater 38F-100(CNG)	$479,473	$1,186,695	2.48
Overall	**$41,824**		

Table B-2. Input Data

Variable	Value	Value	Value	Value	Value	Value	Value	Value	Value	Value	Value	Unit
Unit ID	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	
Maximum Heat Input Rate [1]	191	98	106	41	47	47	91	108	162	48	45	MMBtu/hr
NO_X Emission Rate [1]	176.74	41.74	21.2	10.1	41.49	41.49	32.37	41.24	9.3	4.3	2.75	tons/year
Actual Annual Fuel Consumption [1]	1,262,440,000	596,264,000	302,905,000	144,245,000	592,681,000	592,681,000	462,420,000	589,213,000	548,397,000	161,265,000	179,677,000	scf/year
Net Plant Heat Input Rate [2]	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	MMBtu/MW
Days of Operation	365	365	365	365	365	365	365	365	365	365	365	days/year
SCR Control Efficiency [3]	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	%
Inlet NO_X [1]	0.275	0.137	0.137	0.137	0.137	0.137	0.137	0.137	0.031	0.042	0.027	lb/MMBtu
Outlet NO_X [3]	0.027	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.003	0.004	0.003	lb/MMBtu
SRF [2]	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	
Operating Life of Catalyst [2]	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	hours
SCR Equipment Life [2]	20	20	20	20	20	20	20	20	20	20	20	years
SCR Inlet Temperature [2]	724	667	861	680	735	738	438	425	303	619	726	°F
Days of Reagent Storage [2]	14	14	14	14	14	14	14	14	14	14	14	days
Interest Rate [4]	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	
Reagent Cost [1]	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$/lb
Electricity Cost [1]	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$/kWh
Catalyst Cost [2]	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$/cubic ft
SCR Reactor Chambers [2]	1	1	1	1	1	1	1	1	1	1	1	
Number of Catalyst Layers [2]	3	3	3	3	3	3	3	3	3	3	3	
Ammonia Slip [2]	2	2	2	2	2	2	2	2	2	2	2	ppm
Operator Labor Rate [1]	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$/hour
Operator Hours/Day [2]	4	4	4	4	4	4	4	4	4	4	4	hours/day

[1] Site-Specific value for the Phillips 66 Refinery

[2] Default value provided in the EPA's Control Cost Manual and associated template calculation workbook.
EPA Air Pollution Control Cost Manual, Seciton 4, Chapter 2 - Selective Catalytic Reduction. Updated June 12, 2019. Accessed March 9 2020. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[3] SCR control efficiency is conservatively selected as the maximum of the range of values provided in the EPA Air Pollution Control Technology Fact Sheet for Selective Catalytic Reduction. https://www3.epa.gov/ttncatc1/cica/files/fscr.pdf

[4] See "A Note on the Interest Rate Used in Cost-Effectiveness Calculations," Appendix B.

Table B-3. Calculated Values

Variable [1]	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Catalyst Future Worth Factor	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	FWF
Adjusted Efficiency Factor	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	EF_{adj}
Adjusted Ammonia Slip Factor	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	$Slip_{adj}$
Adjusted NOX Inlet Rate	0.940	0.896	0.896	0.896	0.896	0.896	0.896	0.896	0.862	0.866	0.861	$NO_{X,adj}$
Adjusted Sulfur Content Factor	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	S_{adj}
Adjusted Temperature	1.0185424	1.0901686	1.5746254	1.05816	1.025215	1.0281856	3.1724656	3.376875	5.7464566	1.2885814	1.0192624	T_{adj}

[1] Values calculated based on the EPA Control Cost Manual, Section 4, Chapter 2 - Selective Catalytic Reduction. Updated June 12, 2019. Accessed March 9 2020. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

Table B-4. SCR Direct Capital Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Purchased Equipment Costs [1]												
SCR Unit	$7,244,612	$4,854,346	$5,088,369	$2,877,832	$3,123,588	$3,123,588	$4,643,227	$5,145,758	$6,563,026	$3,163,296	$3,043,145	SCR_{cost}
Instrumentation	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.1 * SCR_{cost}
Sales Tax	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.03 * SCR_{cost}
Freight	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.05 * SCR_{cost}
Subtotal, Purchased Equipment Cost	$7,244,612	$4,854,346	$5,088,369	$2,877,832	$3,123,588	$3,123,588	$4,643,227	$5,145,758	$6,563,026	$3,163,296	$3,043,145	PEC
Direct Installation Costs [1]	$4,038,426	$2,706,000	$2,836,453	$1,604,214	$1,741,209	$1,741,209	$2,588,314	$2,868,444	$3,658,483	$1,763,343	$1,696,366	
Site Preparation	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	
Buildings	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	
Total Direct Cost	**$11,283,037**	**$7,560,346**	**$7,924,822**	**$4,482,046**	**$4,864,797**	**$4,864,797**	**$7,231,541**	**$8,014,202**	**$10,221,509**	**$4,926,639**	**$4,739,511**	

[1] SCR capital and installation costs based on vendor quote and installation costs for the FCC Vacuum Heater (Unit ID 4F-2) in 2008. Costs are provided in 2008$ and scaled using the 0.6 rule and the following maximum heat inputs:

Heat Input for Original Unit	189	189	189	189	189	189	189	189	189	189	189	MMBtu/hr
Heat Input for 1F-1	191	98	106	41	47	47	91	108	162	48	45	MMBtu/hr

Table B-5. SCR Indirect Capital Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100
Construction Support and Management	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150
Detailed Design	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl
Permitting and Plan Checks	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl
Contingencies	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000
Escalation	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300
Total Indirect Cost	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**

Total Capital Investment (TCI) (2008 $)	**$16,615,487**	**$12,892,796**	**$13,257,272**	**$9,814,496**	**$10,197,247**	**$10,197,247**	**$12,563,991**	**$13,346,652**	**$15,553,959**	**$10,259,089**	**$10,071,961**

Table B-6. SCR Direct Annual Costs

Variable	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Units
Hours per Year	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	hours
Operating Labor												
Man-hrs	1460	1460	1460	1460	1460	1460	1460	1460	1460	1460	1460	hours
Rate	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$/hour
Subtotal, Operating Labor	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$
Maintenance												
Maintenance	$83,077	$64,464	$66,286	$49,072	$50,986	$50,986	$62,820	$66,733	$77,770	$51,295	$50,360	
Subtotal, Maintenance	$83,077	$64,464	$66,286	$49,072	$50,986	$50,986	$62,820	$66,733	$77,770	$51,295	$50,360	
Electricity												
Demand (kW)	98.21	50.39	54.50	21.08	24.17	24.17	46.79	55.53	83.30	24.68	23.14	
Cost ($/kW-hr)	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	
Subtotal, Electricity	$46,045	$23,625	$25,554	$9,884	$11,330	$11,330	$21,938	$26,036	$39,054	$11,571	$10,848	
Reagent Cost[1]												
Amount Required	160,653	41,215	44,579	17,243	19,766	19,766	38,271	45,420	15,502	6,221	3,664	lb/yr
Cost	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$/lb
Subtotal, Reagent	$17,691	$4,539	$4,909	$1,899	$2,177	$2,177	$4,214	$5,002	$1,707	$685	$403	
Catalyst Replacement Cost												
Catalyst Replaced Annually	718	376	587	153	170	170	1016	1283	3152	210	155	
Cost	$18,680	$9,778	$15,277	$3,971	$4,410	$4,423	$26,423	$33,380	$81,972	$5,469	$4,032	
Subtotal, Catalyst	$18,680	$9,778	$15,277	$3,971	$4,410	$4,423	$26,423	$33,380	$81,972	$5,469	$4,032	
Total Direct Annual Costs (2008 $)	**$269,398**	**$206,310**	**$215,930**	**$168,730**	**$172,808**	**$172,820**	**$219,299**	**$235,055**	**$304,407**	**$172,925**	**$169,547**	

[1] Reagent Cost ($) = Cost ($/lb) * Maximum Heat Input Rate (MMBTU/hr) * Inlet NOx (lb/MMBTU) * Maximum Hours (hrs/yr)* SCR control Efficiency (%) * SRF (%) * MW Reagent (g/mol) / MW NO_2 (g/mol)

Table B-7. SCR Indirect Annual Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Administrative Charges	$4,114	$3,891	$3,913	$3,706	$3,729	$3,729	$3,871	$3,918	$4,050	$3,733	$3,721	AC = 0.03 x (Operator Cost + 0.4* Annual Maintenance Cost)
Capital Recovery	$1,568,384	$1,216,989	$1,251,393	$926,419	$962,548	$962,548	$1,185,952	$1,259,829	$1,468,184	$968,385	$950,722	CRF

Total Indirect Annual Cost (2008 $)	**$1,572,499**	**$1,220,879**	**$1,255,305**	**$930,125**	**$966,277**	**$966,277**	**$1,189,823**	**$1,263,747**	**$1,472,234**	**$972,118**	**$954,443**

Table B-8. SCR Cost Summary

Variable	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Units
Total Annualized Cost [1]	$1,944,651	$1,506,809	$1,553,311	$1,160,157	$1,202,631	$1,202,645	$1,487,733	$1,582,416	$1,875,755	$1,208,922	$1,186,695	2019$/year
Pollutant Emission Rate Prior to SCR	176.74	41.74	21.2	10.1	41.49	41.49	32.37	41.24	9.3	4.3	2.75	tons NO_X/yr
Pollutant Removed	159.07	37.57	19.08	9.09	37.34	37.34	29.13	37.12	8.37	3.87	2.48	tons NO_X/yr
Cost Per Ton of Pollutant Removed	$12,225	$40,111	$81,410	$127,630	$32,207	$32,207	$51,067	$42,634	$224,104	$312,383	$479,473	$/ton

[1] Adjusted to 2019 dollars (the most recent published annual data) using the Chemical Engineering Plant Cost Index. https://www.chemengonline.com/pci-home

Table B-9. LNB Cost Calculation Summary

Emission Unit ID	LNB Cost Effectiveness ($/ton removed)	Total Annualized Cost ($/year)	Total Pollutant Removed (tons)
Crude Heater 1F-1	$14,271	$382,016	26.77
#2 Crude Heater 1F-1A	$19,636	$214,872	10.94
#3 Pretreater Heater 18F-1	$35,848	$121,694	3.39
#3 Reformer Heater 18F-21	$15,998	$87,093	5.44
18F-22	$15,998	$87,093	5.44
#3 Reformer Heater 18F-23	$15,998	$87,093	5.44
18F-24	$15,998	$87,093	5.44
No. 2 Boiler 22F-1A .	$9,643	$81,829	8.49
No. 3 Boiler 22F-1B .	$7,572	$81,829	10.81

Table B-10. Input Data

Variable	Value	Value	Value	Value	Value	Value	Value	Value [5]	Value [5]	Unit
Unit ID	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	
Maximum Heat Input Rate [1]	191	98	41	47	47	47	47	91	108	MMBtu/hr
Baseline NO_X Emission Rate [1]	176.74	41.74	10.1	20.75	20.75	20.75	20.75	32.37	41.24	tons/year
Fuel HHV [2]	1,033	1,033	1,033	1,033	1,033	1,033	1,033	1,033	1,033	Btu/scf
Actual Annual Fuel Consumption [1]	1,262,440,000	596,264,000	144,245,000	296,340,500	296,340,500	296,340,500	296,340,500	462,420,000	589,213,000	scf/year
Days of Operation	365	365	365	365	365	365	365	365	365	days/year
Low NOX Emissions [3]	0.23	0.1	0.09	0.1	0.1	0.1	0.1	0.1	0.1	lb/MMBtu
	149.97	30.80	6.71	15.31	15.31	15.31	15.31	23.88	30.43	tons/year
Control Efficiency	15%	26%	34%	26%	26%	26%	26%	26%	26%	
Interest Rate [4]	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	
Estimated Equipment Life	20	20	20	20	20	20	20	20	20	years
Chemical Engineering Plant Cost Index										
2019	607.5	607.5	607.5	607.5	607.5	607.5	607.5	607.5	607.5	
2004	444.2	444.2	444.2	444.2	444.2	444.2	444.2	444.2	444.2	

[1] Site-Specific value for the Phillips 66 Refinery

[2] Default value provided in the EPA's Control Cost Manual and associated template calculation workbook for various control technologies.

[3] LNB Emission rates based on vendor data.

[4] Bank prime loan rate obtained from the Federal Reserve, accessed on March 9, 2020. https://www.federalreserve.gov/releases/h15/

[5] Conversion of NOX emission guarantee from ppmv to lb/MMBtu developed using the following values:

Molecular Weight, Flue Gas	27.7
Molecular Weight, NOX	46.01

The following equation is used for the conversion:

$$\frac{scf\ NO_X}{scf\ flue} \times \frac{lb\ flue}{hr} \times \frac{lb\ NO_X}{scf\ NO_X} \times \frac{scf\ flue}{lb\ flue} = \frac{lb\ NO_X}{hr}$$

The density of a gas is calculated using the following:

$$\frac{lb\ X}{scf\ X} = \frac{P}{MW_X RT}$$

Therefore, the density equations offset, resulting in a factor of:

$$\frac{lb\ NO_X}{scf\ NO_X} \times \frac{scf\ flue}{lb\ flue} = \frac{MW_{flue}}{MW_{NO_X}}$$

Table B-11. LNB Direct Capital Costs

Cost	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	Notation
Purchased Equipment Costs [1]										
Low-NOX Burner Unit	$1,172,000	$581,000	$340,000	$242,500	$242,500	$242,500	$242,500	$286,000	$286,000	A
Instrumentation	$117,200.0	$58,100.0	$34,000.0	$24,250.0	$24,250.0	$24,250.0	$24,250.0	Incl.	Incl.	0.1 * A
Sales Tax	$35,160.00	$17,430.00	$10,200.00	$7,275.00	$7,275.00	$7,275.00	$7,275.00	$8,580.00	$8,580.00	0.03 * A
Freight	$58,600.00	$29,050.00	$17,000.00	$12,125.00	$12,125.00	$12,125.00	$12,125.00	$14,300.00	$14,300.00	0.05 * A
Subtotal, Purchased Equipment Cost	$1,382,960	$685,580	$401,200	$286,150	$286,150	$286,150	$286,150	$308,880	$308,880	PEC
Direct Installation Costs [1]	$1,100,000	$735,000	$400,000	$287,500	$287,500	$287,500	$287,500	Incl.	Incl.	DI
Total Direct Cost	**$2,482,960**	**$1,420,580**	**$801,200**	**$573,650**	**$573,650**	**$573,650**	**$573,650**	**$308,880**	**$308,880**	DC = PEC + DI

[1] LNB costs are based on vendor estimates. Costs not included in the vendor estimate are based on the EPA Control Cost Manual methodologies.
"OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

Table B-12. LNB Indirect Capital Costs

Cost	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	Notation
Overhead & Contingencies										
Engineering	$138,296	$68,558	$40,120	$28,615	$28,615	$28,615	$28,615	Incl.	Incl.	0.1 * PEC
Construction & Field Expenses	Incl.	Incl.	Incl.	Incl.	Incl.	Incl.	Incl.	Incl.	Incl.	0.05 * PEC
Contractor Fee	$138,296	$68,558	$40,120	$28,615	$28,615	$28,615	$28,615	Incl.	Incl.	0.1 * PEC
Start-Up	$27,659	$13,712	$8,024	$5,723	$5,723	$5,723	$5,723	Incl.	Incl.	0.02 * PEC
Performance Testing	$13,830	$6,856	$4,012	$2,862	$2,862	$2,862	$2,862	Incl.	Incl.	0.01 * PEC
Contingencies	$41,489	$20,567	$12,036	$8,585	$8,585	$8,585	$8,585	Incl.	Incl.	0.03 * PEC
Total Indirect Cost	**$359,570**	**$178,251**	**$104,312**	**$74,399**	**$74,399**	**$74,399**	**$74,399**	**$300,000**	**$300,000**	

[1] Indirect installation costs developed using methods consistent with the previous ULNB BACT calculations for the #4 Boiler.
"OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

Total Capital Investment (TCI)	**$2,842,530**	**$1,598,831**	**$905,512**	**$648,049**	**$648,049**	**$648,049**	**$648,049**	**$608,880**	**$608,880**

Table B-13. LNB Direct Annual Costs

Variable	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	Units
Hours per Year	8760	8760	8760	8760	8760	8760	8760	8760	8760	hours
Operating Labor	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Maintenance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Total Direct Annual Costs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	

Table B-14. LNB Indirect Annual Costs

Cost	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	Notation
Administrative Charges	$56,851	$31,977	$18,110	$12,961	$12,961	$12,961	$12,961	$12,178	$12,178	0.02 * TCI
Insurance	$28,425	$15,988	$9,055	$6,480	$6,480	$6,480	$6,480	$6,089	$6,089	0.01 * TCI
Property Tax	$28,425	$15,988	$9,055	$6,480	$6,480	$6,480	$6,480	$6,089	$6,089	0.01 * TCI
Capital Recovery	$268,315	$150,918	$85,474	$61,171	$61,171	$61,171	$61,171	$57,474	$57,474	CRF * TCI
Total Indirect Annual Cost	**$382,016**	**$214,872**	**$121,694**	**$87,093**	**$87,093**	**$87,093**	**$87,093**	**$81,829**	**$81,829**	

Table B-15. LNB Cost Summary

Variable	1F-1	1F-1A	18F-1	18F-21	18F-22	18F-23	18F-24	22F-1A	22F-1B	Units
Total Annualized Cost	$382,016	$214,872	$121,694	$87,093	$87,093	$87,093	$87,093	$81,829	$81,829	2019$/year
Emission Rate Prior to Burner Replacement	176.74	41.74	10.1	20.75	20.75	20.75	20.75	32.37	41.24	tons NO_X/yr
Pollutant Removed	27	11	3	5	5	5	5	8	11	tons NO_X/yr
Cost Per Ton of Pollutant Removed	$14,271	$19,636	$35,848	$15,998	$15,998	$15,998	$15,998	$9,643	$7,572	$/ton

A Note on the Interest Rate Used in the Cost-Effectiveness Calculations

The cost analyses in this report follow OMB's guidance by using an interest rate of 7% for evaluating the cost of capital recovery, as discussed below.

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[7]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[8] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[9] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%. "As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."[10]

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[7] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[8] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[9] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[10] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

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Chris Hanlon-Meyer
Science and Engineering Section Manager
Air Quality Program, WA State Dept of Ecology
300 Desmond Drive SE
Lacey, WA 98503

April 30, 2020
HSE450.015.Regional Haze

RE: Phillips 66 Ferndale Refinery Four Factor Analysis

Dear Mr. Hanlon-Meyer,

Attached you will find the Phillips 66 Ferndale Refinery Four Factor Analysis, to be incorporated into Ecology's Regional Haze effort. As we discussed on our call last week, analysis has been completed for selective catalytic reduction (SCR) and is included in this analysis. Analysis of low-NOx burner retrofits is in progress, but has been delayed on several fronts by the Covid-19 coronavirus. The Phillips 66 Ferndale Refinery Four Factor Analysis will be revised and resubmitted once the assessment of low-NOx burners is complete.

Please don't hesitate to contact me at (360) 384-8217 if you have questions or concerns.

Sincerely,

Erin Strang

Erin Strang

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Phillips 66 > Ferndale, WA Refinery

Prepared By:

Aaron Day – Principal Consultant
Melissa Hillman – Principal Consultant
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April 2020

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1. EXECUTIVE SUMMARY

On November 27, 2019, Ecology sent a letter to P66 requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" P66's Ferndale, WA refinery.[1] P66 understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the P66 Ferndale refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, P66 understands that Ecology will only move forward with requiring emission reductions from the P66 Ferndale refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost-effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus the control cost development on low-NO_X burners (LNB) and selective catalytic reduction (SCR). For NO_X emissions, a complete four-factor analysis is provided for SCR at this time. For completeness, a qualitative discussion of each of the remaining pollutants is also included in this analysis.

P66 concludes that SCR is likely technically feasible for the units evaluated in this report, although further engineering analysis would be required to conclusively confirm SCR's feasibility for each unit in question. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

For the purposes of this analysis, cost calculations are currently being developed for LNBs. Because heater-specific factors including fan capacity, internal geometry, combustion air system design, and flow conditions can influence the feasibility of LNB retrofits, there are potentially engineering constraints that would make the implementation of LNBs technically infeasible. While P66 has not ruled out LNB retrofits on the basis of technical feasibility within this analysis, it is important to note that a more thorough, unit-specific evaluation will be required to determine if the installation of LNBs is technically feasible. LNB cost-effectiveness metrics are lower than those of SCR but are expected to still be economically infeasible to retrofit in many cases. P66 concludes that the existing emissions reduction method of good combustion practices is consistent with the specified technology in recent determinations for units of similar size under more stringent regulatory programs (e.g., the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.[2]

[1] Letter from Ecology to P66 dated November 27, 2019.

[2] Search results from the EPA's RACT/BACT/LAER Clearinghouse database are provided in Appendix A of this report.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

(A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On November 27, 2019, Ecology sent a letter to P66 requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" P66's Ferndale, WA refinery.[3] P66 understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the P66 Ferndale refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, P66 understands that Ecology will only move forward with requiring emission reductions from the P66 Ferndale refinery if the emission reductions are both cost-effective and needed to show reasonable progress. Control options are only relevant for the Regional Haze Rule if they result in a meaningful reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

[3] Letter from Chris Hanlon-Meyer, Ecology to Erin Strang, P66, dated November 27, 2019.

In the November 27 request letter, Ecology additionally requested that P66 "include all information regarding activities that have the potential to reduce the cost of compliance." As a standard practice, the refinery evaluates projects undertaken at the refinery for the potential to reduce costs through energy efficient design and timing of maintenance.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA) dated March 9, 2020, Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus on control cost development for low-NO_X burners and selective catalytic reduction (SCR). For NO_X emissions, a complete four-factor analysis is provided for SCR and will be provided at a later date for low-NO_X burners once a preliminary technical feasibility and cost analysis has been completed. A qualitative discussion of each of the remaining pollutants is also included in this analysis.

The information presented in this report for NO_X controls considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the units

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[4] for conducting a review of Best Available Retrofit Technology (BART) for a unit. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for NO_X can be found in Section 6 of this report. A qualitative review of the other pollutants included in the initial four-factor analysis request (SO_2, PM_{10}, NH_3, and H_2SO_4) is provided in Section 5. Section 4 of this report includes information on the P66's existing/baseline emissions for the emission units relevant to Ecology's regional haze efforts.

[4] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

3. SOURCE DESCRIPTION

The Ferndale Refinery is located at 3901 Unick Road in Ferndale, Whatcom County, Washington. The refinery is located on the coastline adjacent to the Strait of Georgia in a rural setting zoned for heavy industrial use. The area surrounding the refinery is designated in attainment with all National Ambient Air Quality Standards.

The Ferndale Refinery is a petroleum refinery that uses crude oil as a feedstock that is processed into a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG) and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline. The crude oil throughput capacity of the refinery is approximately 108,000 barrels per day.

The refining process at the Ferndale Refinery is described as follows. Crude oil enters the refining process at the Crude Distillation Unit where hydrocarbon is separated into light and heavy fractions based on their boiling point. These fractions or “cuts” are routed to other process units where they undergo catalytic cracking, catalytic reforming, isomerization, alkylation, or treatment. Treating systems are used to remove or reduce fuel impurities such as sulfur and benzene. Sulfur is recovered in the Sulfur Recovery Unit (SRU) as elemental sulfur. Some of the lighter hydrocarbons are flashed off as gases during processing and used as fuel in the refinery’s fuel gas systems. The refinery has an oily wastewater system that routes hydrocarbon-bearing wastewater to the refinery’s wastewater treatment system prior to discharge into the Strait of Georgia. In final processing, fuel components are blended into finished products and stored. Finished products are shipped to market via ship, barge, pipeline, railcar, or truck.

It is worth noting that the Ferndale refinery barely exceeded the Q/d screening threshold used by Ecology to determine which facilities are candidates for the Reasonable Available Control Technology (RACT)/four-factor analysis. With a cutoff of 10 for the Q/d ratio (the ratio of facility emissions over the distance to the nearest Class I area), P66 had a Q/d of only 10.88. This is due in part to the improvements P66 has made to the Ferndale refinery during the current planning period to provide greater levels of emission control for NO_X. These retrofits were unrelated to Regional Haze but represent approximately a 20% reduction in NO_X emissions from the 2008-2009 average NO_X emissions to the 2014-2018 average NO_X emissions, which serves as the baseline emissions period for this regional haze four-factor analysis.

In the time period since the first planning period of the regional haze program, P66 has made the following improvements to the facility, reducing the emission of visibility impairing pollutants:

- The Fluid Catalytic Cracking Unit (FCCU) Vacuum Heater (Unit 4F-2) was retrofitted with SCR in 2008.
  - This retrofit resulted in an average annual emission decrease of 102.9 tons per year of NO_X.
- The FCCU CO Boiler was retrofitted with Enhanced Selective Non-Catalytic Reduction (ESNCR) in 2010.
  - This retrofit resulted in an average annual emission decrease of 21.0 tons per year of NO_X.
- A redundant Flare Gas Recovery Compressor was added in 2011.
  - This retrofit resulted in an average annual emission decrease of 27.7 tons per year of NO_X.

Figure 3-1. Aerial View of the Ferndale Refinery

Per the four-factor analysis request from Ecology, the following units require completion of a four factor analysis if they have not been retrofitted since 2005:

- Fluid Catalytic Cracking Units (FCCUs)
- Boilers greater than 40 MMBtu/hr
- Heaters greater than 40 MMBtu/hr

Considering these source types and the timeline of projects at the P66 refinery, the following units require a four-factor analysis.

Table 3-1. Summary of Units Requiring Four-Factor Analyses at the Phillips 66 Refinery

Process Unit	Unit ID	Unit Description	Maximum Heat Input (MMBtu/hr)	Date Constructed	Date Retrofitted	Control Device(s) Currently Installed	Pollutant(s) Controlled
Crude	1F-1	Crude Heater	191	1953	N/A	--	--
	1F-1A	Crude Heater	98	1972	N/A	--	--
Alky	17F-1	Alky Heater	106	1965	N/A	--	--
Reformer	18F-1	Pretreater Heater	41	1972	N/A	--	--
	18F-21	Reformer Heater	47	1972	N/A	--	--
	18F-22	Reformer Heater	47	1972	N/A	--	--
	18F-23	Reformer Heater	47	1972	N/A	--	--
	18F-24	Reformer Heater	47	1972	N/A	--	--
Boilers	22F-1C	#1 Boiler	162	1996	N/A	Flue Gas Recirculation and Low-NO_X Burners	NO_X
	22F-1A	#2 Boiler	91	1953	N/A	--	--
	22F-1B	#3 Boiler	108	1953	N/A	--	--
DHT	33F-1	DHT Heater	48	1992	2001	--	--
S-Zorb	38F-100	S-Zorb Heater	46	2003	N/A	Low-NO_X Burners	--

Baseline emissions from the units listed in Section 3 of this report are calculated based on a mass balance on the fuel combusted. Emissions used for this four-factor analysis are consistent with those submitted for the Washington Emissions Inventory Reporting System (WEIRS). To develop an emissions baseline, based on recent data for the facility and representative of anticipated actual emissions for the near future, WEIRS emissions data from the period of 2014-2018 was analyzed. For the purposes of this analysis, the average of the 5 years of emissions is used as the baseline against which potential emissions reductions and the associated control costs are compared. Emissions from the applicable units at the P66 refinery are provided in Table 4-1 and Table 4-2 below.

Table 4-1. Baseline Emissions Summary – All Applicable Units

Pollutant	Baseline Emissions (tons)
NO_X	422.71
SO_2	7.60
PM_{10}	8.15
NH_3	0.00
H_2SO_4	0.67

Table 4-2. Baseline Emissions Summary - Individual Units

Emission Unit	Annual Emissions (tons)				
	PM_{10}	SO_2	NO_X	H_2SO_4	NH_3
Crude Heater 1F-1	1.89	2.13	176.74	1.14E-01	0.00
#2 Crude Heater 1F-1A	0.89	1.00	41.74	5.82E-02	0.00
Alkylation Heater 17F-1	0.45	0.51	21.20	2.29E-03	0.00
#3 Pretreater Heater 18F-1	0.22	0.12	10.10	6.34E-03	0.00
#3 Reformer Heater 18F-21	0.89	0.50	41.49	1.20E-02	0.00
18F-22 (Included with Above)					
#3 Reformer Heater 18F-23	0.89	0.50	41.49	1.18E-02	0.00
18F-24 (Included with Above)					
No. 1 Boiler 22F-1C	0.82	0.91	9.30	1.63E-01	0.00
No. 2 Boiler 22F-1A	0.69	0.76	32.37	1.34E-01	0.00
No. 3 Boiler 22F-1B	0.88	0.99	41.24	1.57E-01	0.00
DHT Heater 33F-1	0.24	0.13	4.30	1.24E-02	0.00
S-Zorb Heater 38F-100(CNG)	0.27	0.05	2.75	1.51E-03	0.00

5. NO_X FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

Per Ecology's direction, the four-factor analysis with complete control cost evaluations will be conducted only for SCR and low-NO_X burners.

The baseline NO_X emission rates that are used in this four-factor analysis are summarized in Table 4-1 and Table 4-2. The basis of the emission rates is provided in Section 4 of this report.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

In order to minimize NO_X emissions from a combustion unit, controls can take the form of either combustion or post-combustion methods. Low-NO_X burners work to limit NO_X formation during combustion, using various methods to reduce peak flame temperature and increase flame length. SCR addresses NO_X emissions post-combustion, using catalyst and reagent to convert NO_X to elemental nitrogen before emissions leave the stack. Both controls are explained in more detail below. Good combustion practices are also described, as they represent the current emissions reduction method for several of the burners and heaters at the refinery.

5.1.1. Combustion Controls

5.1.1.1. Low-NO_X (LNB)

Low -NO_X burners (LNB) are perhaps the most widely used NO_X control devices for refinery process heaters today. Different burner manufactures use different burner designs to achieve low NO_X emissions, but all designs essentially implement two fundamental tactics - low excess air and staged combustion. Low excess air decreases the total amount of nitrogen present at the burner, thereby decreasing the resulting thermal NO_X formation. Staged combustion burns fuel in two or more steps. The primary combustion zone is fuel-rich, and the secondary zones are fuel-lean. Using these tactics, LNBs inhibit thermal NO_X formation by controlling the flame temperature and the fuel/air mixture within the flame burner zone.

5.1.1.2. Good Combustion Practices

NO_X emissions can be controlled by maintaining various operational combustion parameters. These operational methods can include staged fuel combustion, staged air combustion, and low excess air combustion. The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. This is an appropriate control option for small heaters in which emissions are considered to be de minimis. Good combustion practices are the selected control option for several emission units found in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, which provides control units required as part of programs more stringent in requirement than the regional haze program, including consent decrees and the Prevention of Significant Deterioration Best Available Control Technology (PSD BACT) program. The detailed RBLC database search results are included in Appendix A of this report.

5.1.2. Post Combustion Controls

5.1.2.1. Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[5] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1. Combustion Controls

5.2.1.1. Low-NO_X Burners

Burner design, operating conditions, and surrounding equipment can heavily influence technical feasibility for burner retrofits. In the case of Boiler #1 (Unit 22F-1C), a LNB is already utilized, with flue gas recirculation as well.

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[5] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

This four-factor analysis does not rule out LNBs on the basis of technical feasibility. Given the limited timeframe for conducting the four-factor analysis and complications caused by the COVID-19 pandemic, unit-specific evaluations by vendors to assess technical feasibility and detailed retrofit costs are still in progress. A more unit-specific evaluation by vendors must be completed to determine whether or not LNBs are technically feasible for each unit.

5.2.1.2. Good Combustion Practices

Good combustion practices are currently employed for all burners and heaters, and are therefore considered technically feasible for the facility. Good combustion practices are considered the baseline emissions reduction method for this analysis, and all emissions reductions estimates use this control as a baseline.

5.2.2. Post Combustion Controls

5.2.2.1. Selective Catalytic Reduction

SCR is a widely accepted emissions control technology for heaters and burners in the industry. While specific circumstances can result in SCR implementation challenges or even infeasibility for a given unit, the technology more broadly is considered technically feasible. However, P66 has not undertaken a detailed engineering review of SCR's technical feasibility for the units at the Ferndale refinery.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

The effectiveness of LNBs varies from unit to unit – specific evaluations are necessary to determine whether a burner retrofit is technically feasible, as well as what level of control will be achieved. The efficiencies are summarized in table 5-1, below. Detailed cost calculations are provided in Appendix B of this report.

Table 5-1. Summary of Emissions Reduction Effectiveness

Emissions Reduction Method	Control Efficiency
Selective Catalytic Reduction (SCR) [1]	90%
Low-NO_X Burners (LNB)	Evaluation in Progress
Good Combustion Practices	Baseline

[1] SCR control efficiency, for the purposes of the cost calculations and four-factor analysis, is assumed to be 90% based on data provided in the EPA Control Technology Fact Sheet for SCR.
https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
The use of this control efficiency is a conservative approximation, and testing would be required on a unit-by-unit basis to determine what level of control is attainable, particularly given concerns of ammonia slip that can result in impacts counter to the goals of the regional haze program.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

5.4.1.1. Selective Catalytic Reduction (SCR) Cost Calculations

SCR cost calculations are developed using a vendor quote and actual project costs for SCR on the Vacuum Heater for the Fluid Catalytic Cracking Unit (FCCU). Where applicable, cost calculations are drawn from the EPA Control Cost Manual.

Costs for each unit are scaled by rated heat input, and costs are converted to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[6]

SCR cost calculations are summarized in Table 5-2. Detailed cost calculations are included in Appendix B.

5.4.1.2. Low-NO_X Burner Cost Calculations

LNB cost calculations are being developed as part of an ongoing engineering and technical feasibility study being performed by Tulsa Heaters.

[6] Jenkins, S. "2019 Chemical Engineering Plant Cost Index Annual Average." 20 March 2020. https://www.chemengonline.com/2019-chemical-engineering-plant-cost-index-annual-average/

Table 5-2. Summary of Cost Calculations for SCR and LNB

Emission Unit	Baseline Emission Rate	SCR			LNB		
		Total Annualized Cost ($/year)	Total Pollutant Removed (ton/year)	Cost Effectiveness ($/ton)	Total Annualized Cost ($/year)	Total Pollutant Removed (ton/year)	Cost Effectiveness ($/ton)
Crude Heater 1F-1	176.74	$1,944,651	159.07	$12,225	Evaluation in Progress		
#2 Crude Heater 1F-1A	41.74	$1,506,809	37.57	$40,111			
Alkylation Heater 17F-1	21.20	$1,553,311	19.08	$81,410			
#3 Pretreater Heater 18F-1	10.10	$1,160,157	9.09	$127,630			
#3 Reformer Heater 18F-21	41.49	$1,202,631	37.34	$32,207			
18F-22 (Included with Above for SCR) [1]							
#3 Reformer Heater 18F-23	41.49	$1,202,645	37.34	$32,207			
18F-24 (Included with Above for SCR) [1]							
No. 1 Boiler 22F-1C	9.30	$1,875,755	8.37	$224,104			
No. 2 Boiler 22F-1A	32.37	$1,487,733	29.13	$51,067			
No. 3 Boiler 22F-1B	41.24	$1,582,416	37.12	$42,634			
DHT Heater 33F-1	4.30	$1,208,922	3.87	$312,383			
S-Zorb Heater 38F-100(CNG)	2.75	$1,186,695	2.48	$479,473			

[1] In the case of units with a shared stack, it is assumed that for the purposes of determining LNB costs that each unit is responsible for an equal portion of the total emissions originating from the stack.

5.4.2. Timing for Compliance

P66 believes that reasonable progress compliant controls (good combustion practices) are already in place. Any changes to heaters or boilers at the refinery would need to be incorporated into the schedule of a future refinery turnaround. Refinery turnarounds are infrequent and complex undertakings that require several years of advance planning. However, if Ecology determines that one of the NO_X reduction options analyzed in this report is necessary to achieve reasonable progress, control system upgrades could be incorporated into a future refinery turnaround.

5.4.3. Energy Impacts and Non-Air Quality Impacts

The cost of energy required to operate SCR has been included in the cost analyses found in Appendix B. To operate the SCR, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Reheating the flue gas, as necessary, for SCR application would also require substantial natural gas usage with an associated increase in direct emissions. The use of NO_X reduction methods that incorporate ammonia injection like SCR leads to increased potential for ammonia slip emissions. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills.

5.4.4. Remaining Useful Life

The remaining useful life for all units evaluated in this analysis is at least 20 years, and thus is not considered to have an impact on the feasibility or applicability of either emissions reduction option being considered.

5.5. NO_X CONCLUSION

P66 concludes that SCR is likely to be technically feasible for the units evaluated in this report. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

For the purposes of this analysis, LNB costs are currently in the process of being developed for retrofitting the burners. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including unit footprint, downstream process units, and flow conditions, there are potentially engineering constraints. While P66 has not ruled out LNB retrofits on the basis of technical feasibility in this analysis, a more thorough, unit-specific evaluation by a project team is required to determine if the installation of low-NO_X burners is technically feasible on a case-by-case basis for every process heater or boiler of interest. This process is in progress, with preliminary results expected sometime this summer. P66 notes that the existing emissions reduction method of good combustion practice is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.

6. PM_{10}, SO_2, NH_3, AND H_2SO_4 EVALUATION

Per Ecology's direction, the only emissions controls being evaluated for a complete four-factor analysis are SCR and low-NO_X burners for NO_X emissions control. Given that the initial four-factor analysis request in November 2019 included PM_{10}, SO_2, NH_3, and H_2SO_4, the following section is provided for completeness. This section of the report provides a qualitative assessment of the four additional pollutants other than NO_X, with conclusions consistent with Ecology's direction that a detailed analysis of these pollutants is not necessary for this submittal.

The baseline emission rates for PM_{10}, SO_2, NH_3, and H_2SO_4 are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

The U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and historic BACT reports for the facility were searched to identify possible control technologies that could be used to reduce PM_{10}, SO_2, NH_3, and H_2SO_4 emissions from applicable units for regional haze at the Ferndale refinery. To ensure all potentially relevant control methodologies were considered, the search was conducted both for combustion units less than 100 MMBtu/hr of heat input and combustion units with a heat input between 100 and 250 MMBtu/hr.

In the case of PM_{10} and H_2SO_4, the RBLC results include only good combustion practices for emissions controls. This is consistent with current practices at the Ferndale refinery, and P66 concludes that no additional controls or emission reduction measures are necessary for the Ferndale refinery.

For SO_2 entries in the RBLC database, the control technologies likewise included combustion practices, with the use of low-sulfur fuels for combustion also included. CEMS are currently used to monitor inlet fuel sulfur content to ensure compliance with the refinery fuel gas sulfur requirements of NSPS Subpart J. Good combustion practices and the use of low-sulfur fuels are consistent with current practices at the Ferndale refinery, and no additional emissions reductions options are required to maintain practices consistent with those found in the RBLC database.

Finally, for NH3 there are currently no appreciable NH3 emissions from the units currently evaluated for the four-factor analysis. Should emissions controls be installed that involve the use of ammonia, then there is the potential for ammonia slip to result; however, there are currently no ammonia-using controls on any of the units covered in this report. Therefore, no additional emission reduction measures are appropriate at this time.

No additional control measures were identified as appropriate for the process heaters and boilers applicable to regional haze at this facility. Therefore, no additional controls or emission reduction options are evaluated for PM_{10}, SO_2, NH_3, and H_2SO_4 in this analysis.

APPENDIX A : RBLC SEARCH RESULTS

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown NOx annual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx anual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Table B-1. SCR Cost Calculation Summary

Emission Unit ID	SCR Cost Effectiveness ($/ton removed)	Total Annualized Cost ($/year)	Total Pollutant Removed (tons)
Crude Heater 1F-1	$12,225	$1,944,651	159.07
#2 Crude Heater 1F-1A	$40,111	$1,506,809	37.57
Alkylation Heater 17F-1	$81,410	$1,553,311	19.08
#3 Pretreater Heater 18F-1	$127,630	$1,160,157	9.09
#3 Reformer Heater 18F-21	$32,207	$1,202,631	37.34
18F-22	Included Above		
#3 Reformer Heater 18F-23	$32,207	$1,202,645	37.34
18F-24	Included Above		
No. 1 Boiler 22F-1C	$224,104	$1,875,755	8.37
No. 2 Boiler 22F-1A	$51,067	$1,487,733	29.13
No. 3 Boiler 22F-1B	$42,634	$1,582,416	37.12
DHT Heater 33F-1	$312,383	$1,208,922	3.87
Szorb Heater 38F-100(CNG)	$479,473	$1,186,695	2.48
Overall	**$41,824**		

Table B-2. Input Data

Variable	Value	Value	Value	Value	Value	Value	Value	Value	Value	Value	Value	Unit
Unit ID	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	
Maximum Heat Input Rate [1]	191	98	106	41	47	47	91	108	162	48	45	MMBtu/hr
NO_X Emission Rate [1]	176.74	41.74	21.2	10.1	41.49	41.49	32.37	41.24	9.3	4.3	2.75	tons/year
Actual Annual Fuel Consumption [1]	1,262,440,000	596,264,000	302,905,000	144,245,000	592,681,000	592,681,000	462,420,000	589,213,000	548,397,000	161,265,000	179,677,000	scf/year
Net Plant Heat Input Rate [2]	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	MMBtu/MW
Days of Operation	365	365	365	365	365	365	365	365	365	365	365	days/year
SCR Control Efficiency [3]	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	%
Inlet NO_X [1]	0.275	0.137	0.137	0.137	0.137	0.137	0.137	0.137	0.031	0.042	0.027	lb/MMBtu
Outlet NO_X [3]	0.027	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.003	0.004	0.003	lb/MMBtu
SRF [2]	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	
Operating Life of Catalyst [2]	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	hours
SCR Equipment Life [2]	20	20	20	20	20	20	20	20	20	20	20	years
SCR Inlet Temperature [2]	724	667	861	680	735	738	438	425	303	619	726	°F
Days of Reagent Storage [2]	14	14	14	14	14	14	14	14	14	14	14	days
Interest Rate [4]	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	
Reagent Cost [1]	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$/lb
Electricity Cost [1]	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$/kWh
Catalyst Cost [2]	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$227.00	$/cubic ft
SCR Reactor Chambers [2]	1	1	1	1	1	1	1	1	1	1	1	
Number of Catalyst Layers [2]	3	3	3	3	3	3	3	3	3	3	3	
Ammonia Slip [2]	2	2	2	2	2	2	2	2	2	2	2	ppm
Operator Labor Rate [1]	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$/hour
Operator Hours/Day [2]	4	4	4	4	4	4	4	4	4	4	4	hours/day

[1] Site-Specific value for the Phillips 66 Refinery

[2] Default value provided in the EPA's Control Cost Manual and associated template calculation workbook.
EPA Air Pollution Control Cost Manual, Seciton 4, Chapter 2 - Selective Catalytic Reduction. Updated June 12, 2019. Accessed March 9 2020. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[3] SCR control efficiency is conservatively selected as the maximum of the range of values provided in the EPA Air Pollution Control Technology Fact Sheet for Selective Catalytic Reduction. https://www3.epa.gov/ttncatc1/cica/files/fscr.pdf

[4] See "A Note on the Interest Rate Used in Cost-Effectiveness Calculations," Appendix B.

Table B-3. Calculated Values

Variable [1]	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Catalyst Future Worth Factor	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	FWF
Adjusted Efficiency Factor	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	1.239	EF_{adj}
Adjusted Ammonia Slip Factor	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	1.170	$Slip_{adj}$
Adjusted NOX Inlet Rate	0.940	0.896	0.896	0.896	0.896	0.896	0.896	0.896	0.862	0.866	0.861	$NO_{X,adj}$
Adjusted Sulfur Content Factor	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964	S_{adj}
Adjusted Temperature	1.0185424	1.0901686	1.5746254	1.05816	1.025215	1.0281856	3.1724656	3.376875	5.7464566	1.2885814	1.0192624	T_{adj}

[1] Values calculated based on the EPA Control Cost Manual, Section 4, Chapter 2 - Selective Catalytic Reduction. Updated June 12, 2019. Accessed March 9 2020. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

Table B-4. SCR Direct Capital Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Purchased Equipment Costs [1]												
SCR Unit	$7,244,612	$4,854,346	$5,088,369	$2,877,832	$3,123,588	$3,123,588	$4,643,227	$5,145,758	$6,563,026	$3,163,296	$3,043,145	SCR_{cost}
Instrumentation	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.1 * SCR_{cost}
Sales Tax	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.03 * SCR_{cost}
Freight	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	0.05 * SCR_{cost}
Subtotal, Purchased Equipment Cost	$7,244,612	$4,854,346	$5,088,369	$2,877,832	$3,123,588	$3,123,588	$4,643,227	$5,145,758	$6,563,026	$3,163,296	$3,043,145	PEC
Direct Installation Costs [1]	$4,038,426	$2,706,000	$2,836,453	$1,604,214	$1,741,209	$1,741,209	$2,588,314	$2,868,444	$3,658,483	$1,763,343	$1,696,366	
Site Preparation	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	
Buildings	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	
Total Direct Cost	**$11,283,037**	**$7,560,346**	**$7,924,822**	**$4,482,046**	**$4,864,797**	**$4,864,797**	**$7,231,541**	**$8,014,202**	**$10,221,509**	**$4,926,639**	**$4,739,511**	

[1] SCR capital and installation costs based on vendor quote and installation costs for the FCC Vacuum Heater (Unit ID 4F-2) in 2008. Costs are provided in 2008$ and scaled using the 0.6 rule and the following maximum heat inputs:

	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	
Heat Input for Original Unit	189	189	189	189	189	189	189	189	189	189	189	MMBtu/hr
Heat Input for 1F-1	191	98	106	41	47	47	91	108	162	48	45	MMBtu/hr

Table B-5. SCR Indirect Capital Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100
Construction Support and Management	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150	$3,841,150
Detailed Design	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl
Permitting and Plan Checks	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl	Incl
Contingencies	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000	$1,323,000
Escalation	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300	$168,300
Total Indirect Cost	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**	**$5,332,450**

	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100
Total Capital Investment (TCI) (2008 $)	**$16,615,487**	**$12,892,796**	**$13,257,272**	**$9,814,496**	**$10,197,247**	**$10,197,247**	**$12,563,991**	**$13,346,652**	**$15,553,959**	**$10,259,089**	**$10,071,961**

Table B-6. SCR Direct Annual Costs

Variable	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Units
Hours per Year	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	hours
Operating Labor												
Man-hrs	1460	1460	1460	1460	1460	1460	1460	1460	1460	1460	1460	hours
Rate	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$71.17	$/hour
Subtotal, Operating Labor	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$103,904	$
Maintenance												
Maintenance	$83,077	$64,464	$66,286	$49,072	$50,986	$50,986	$62,820	$66,733	$77,770	$51,295	$50,360	
Subtotal, Maintenance	$83,077	$64,464	$66,286	$49,072	$50,986	$50,986	$62,820	$66,733	$77,770	$51,295	$50,360	
Electricity												
Demand (kW)	98.21	50.39	54.50	21.08	24.17	24.17	46.79	55.53	83.30	24.68	23.14	
Cost ($/kW-hr)	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	
Subtotal, Electricity	$46,045	$23,625	$25,554	$9,884	$11,330	$11,330	$21,938	$26,036	$39,054	$11,571	$10,848	
Reagent Cost[1]												
Amount Required	160,653	41,215	44,579	17,243	19,766	19,766	38,271	45,420	15,502	6,221	3,664	lb/yr
Cost	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$/lb
Subtotal, Reagent	$17,691	$4,539	$4,909	$1,899	$2,177	$2,177	$4,214	$5,002	$1,707	$685	$403	
Catalyst Replacement Cost												
Catalyst Replaced Annually	718	376	587	153	170	170	1016	1283	3152	210	155	
Cost	$18,680	$9,778	$15,277	$3,971	$4,410	$4,423	$26,423	$33,380	$81,972	$5,469	$4,032	
Subtotal, Catalyst	$18,680	$9,778	$15,277	$3,971	$4,410	$4,423	$26,423	$33,380	$81,972	$5,469	$4,032	
Total Direct Annual Costs (2008 $)	**$269,398**	**$206,310**	**$215,930**	**$168,730**	**$172,808**	**$172,820**	**$219,299**	**$235,055**	**$304,407**	**$172,925**	**$169,547**	

[1] Reagent Cost ($) = Cost ($/lb) * Maximum Heat Input Rate (MMBTU/hr) * Inlet NOx (lb/MMBTU) * Maximum Hours (hrs/yr)* SCR control Efficiency (%) * SRF (%) * MW Reagent (g/mol) / MW NO_2 (g/mol)

Table B-7. SCR Indirect Annual Costs

Cost	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Notation
Administrative Charges	$4,114	$3,891	$3,913	$3,706	$3,729	$3,729	$3,871	$3,918	$4,050	$3,733	$3,721	AC = 0.03 x (Operator Cost + 0.4* Annual Maintenance Cost)
Capital Recovery	$1,568,384	$1,216,989	$1,251,393	$926,419	$962,548	$962,548	$1,185,952	$1,259,829	$1,468,184	$968,385	$950,722	CRF

	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100
Total Indirect Annual Cost (2008 $)	**$1,572,499**	**$1,220,879**	**$1,255,305**	**$930,125**	**$966,277**	**$966,277**	**$1,189,823**	**$1,263,747**	**$1,472,234**	**$972,118**	**$954,443**

Table B-8. SCR Cost Summary

Variable	1F-1	1F-1A	17F-1	18F-1	18F-21	18F-23	22F-1A	22F-1B	22F-1C	33F-1	38F-100	Units
Total Annualized Cost [1]	$1,944,651	$1,506,809	$1,553,311	$1,160,157	$1,202,631	$1,202,645	$1,487,733	$1,582,416	$1,875,755	$1,208,922	$1,186,695	2019$/year
Pollutant Emission Rate Prior to SCR	176.74	41.74	21.2	10.1	41.49	41.49	32.37	41.24	9.3	4.3	2.75	tons NO_X/yr
Pollutant Removed	159.07	37.57	19.08	9.09	37.34	37.34	29.13	37.12	8.37	3.87	2.48	tons NO_X/yr
Cost Per Ton of Pollutant Removed	$12,225	$40,111	$81,410	$127,630	$32,207	$32,207	$51,067	$42,634	$224,104	$312,383	$479,473	$/ton

[1] Adjusted to 2019 dollars (the most recent published annual data) using the Chemical Engineering Plant Cost Index. https://www.chemengonline.com/pci-home

A Note on the Interest Rate Used in the Cost-Effectiveness Calculations

The cost analyses in this report follow OMB's guidance by using an interest rate of 7% for evaluating the cost of capital recovery, as discussed below.

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[7]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[8] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[9] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%. "As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."[10]

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[7] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[8] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[9] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[10] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

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April 30, 2020

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Chris Hanlon-Meyer
Science and Engineering Section Manager – Air Quality Program
State of Washington Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

Subject: Puget Sound Refinery (PSR) Regional Haze 4-Factor Analysis Report Submittal

Dear Mr. Hanlon-Meyer:

On November 27, 2019, Washington Department of Ecology (Ecology) sent a letter to Shell requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" Shell's Puget Sound Refinery (PSR).[1] Shell understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals under the Regional Haze program for Washington. The purpose of this report submittal is to provide information to Ecology regarding potential PM10, SO2, NOX, H2SO4, and NH3 emission reduction options for the Shell Puget Sound Refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, Shell understands that Ecology will only move forward with requiring emission reductions from the Shell Puget Sound Refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost-effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus the control cost development on low-NOX burners (LNB) and selective catalytic reduction (SCR) for NOX emissions. Therefore, a complete four-factor analysis is provided for SCR and low-NOX burners. For completeness, a qualitative discussion of each of the remaining pollutants is included in this analysis.

[1] Letter from Ecology to Shell dated November 27, 2019.

Shell concludes that SCR is technically feasible for the units evaluated in this report. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NOX emissions at the refinery.

For the purposes of this analysis, LNB costs are developed for low-NOX burners. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including unit footprint, downstream process units, and flow conditions, there are potential engineering constraints on its implementation. While Shell has not ruled out LNB retrofits on the basis of technical feasibility in this analysis, it is important to note that a more thorough, unit-specific evaluation by burner vendors will be required to determine if the LNB installation is technically feasible. LNB cost-effectiveness metrics are lower than those of SCR.

The existing emissions reduction method of good combustion practice for those units at the PSR that do not have SCR is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goal

PSR is pleased to be working with DOE to fulfill our requirements with regard to the 4-Factor analysis and as such we are ready to answer any questions that may arise from the submittal of this report. Please contact Aaron Vahid of my staff at 360-293-0865 with any inquiries.

Sincerely,

John W White

John White
General Manager

Enclosed: Regional Haze Four-Factor Analysis Report

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Shell Puget Sound Refinery > Anacortes, WA Refinery

Prepared By:

Aaron Day – Principal Consultant
Sam Najmolhoda – Associate Consultant

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April 2020

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1. EXECUTIVE SUMMARY

On November 27, 2019, Washington Department of Ecology (Ecology) sent a letter to Shell requesting that they provide “information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at” Shell’s Puget Sound Refinery (PSR).[1] Shell understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals under the Regional Haze program for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the Shell Puget Sound Refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology’s request, Shell understands that Ecology will only move forward with requiring emission reductions from the Shell Puget Sound Refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost-effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology’s Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus the control cost development on low-NO_X burners (LNB) and selective catalytic reduction (SCR) for NO_X emissions. Therefore, a complete four-factor analysis is provided for SCR and low-NO_X burners. For completeness, a qualitative discussion of each of the remaining pollutants is included in this analysis.

Shell concludes that SCR is technically feasible for the units evaluated in this report. SCR cost calculations are developed using project costs and vendor data for a previous SCR retrofit at the refinery. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

For the purposes of this analysis, LNB costs are developed for low-NO_X burners. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including unit footprint, downstream process units, and flow conditions, there are potential engineering constraints on its implementation. While Shell has not ruled out LNB retrofits on the basis of technical feasibility in this analysis, it is important to note that a more thorough, unit-specific evaluation by burner vendors will be required to determine if the LNB installation is technically feasible. LNB cost-effectiveness metrics are lower than those of SCR.

The existing emissions reduction method of good combustion practice for those units at the PSR that do not have SCR is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington’s reasonable progress toward visibility goals.

[1] Letter from Ecology to Shell dated November 27, 2019.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

(A) *consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*

(B) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On November 27, 2019, Ecology sent a letter to Shell requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" Shell's Puget Sound Refinery in Anacortes, WA. Shell understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the Shell Puget Sound Refinery. Based on the RHR, associated EPA guidance, and Ecology's request, Shell understands that Ecology will only move forward with requiring emission reductions from the Shell Puget Sound Refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to Ecology. In other words, control options are only relevant for the RHR if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

In email correspondence with Bob Poole of the WSPA, Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus on control cost development for low-NO_X burners and SCR. For NO_X emissions, a complete four-factor analysis is provided for

SCR and low-NO_X burners. For completeness, a qualitative discussion of each of the remaining pollutants is also included in this analysis.

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the emission units

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[2] for conducting a review of Best Available Retrofit Technology (BART) for a unit. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 can be found in Sections 5-9 of this report, respectively. Section 4 of this report includes information on the Shell's existing/baseline emissions for the heaters and boilers relevant to Ecology's regional haze efforts.

[2] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

3. SOURCE DESCRIPTION

The Puget Sound Refinery produces petroleum-based fuels as classified under the Standard Industrial Classification code 2911. It is located on March Point, a heavy industrial area near Anacortes, Washington. The refinery was originally built by Texaco, Inc. and began operation in 1958. Texaco owned and operated the facility until Texaco formed an alliance with Shell Oil Company on January 1, 1998. The resulting company was Equilon Enterprises LLC (Equilon). In April of 2002, Shell purchased Texaco's interest in Equilon. As such, PSR is now owned by Equlion Enterprises LLC doing business as (dba) Shell Oil Products US.

Shell also owns and operates a cogeneration facility on the refinery site. The cogeneration facility was originally the March Point Cogeneration Company (MPCC), which PSR took possession of in February 2010.

Air Liquide and Linde operate hydrogen plants on property owned by PSR and adjacent to the refinery. However, both Air Liquide and Linde are independent companies and are permitted separately from PSR. Emission sources from Air Liquide and Linde are not addressed in this report.

PSR is located between Highway 20 to the south and the Marathon refinery to the north. Figure 3-1 is an aerial view of the refinery.

Figure 3-1. Aerial View of the Puget Sound Refinery

Per the four-factor analysis request from Ecology, the following units require completion of a four factor analysis if they have not been retrofitted since 2005:

- Fluid Catalytic Cracking Units (FCCUs)
- Boilers greater than 40 MMBtu/hr
- Heaters greater than 40 MMBtu/hr

Taking into account these source types and the timeline of projects at the Shell refinery, the following units require a four-factor analysis.

Table 3-1. Summary of Units Requiring Four-Factor Analyses at the Shell Refinery

Process Area	Unit ID	Unit Description	Current Control Equipment	NWAPA NOC Date	Design Firing Rate (MMBtu/hr)
Vacuum Pipe Still (VPS)	1A-F5	VPS Charge Heater #1	Low NO_X Burners	9/12/2005 OAC 919	415 (hourly)
	1A-F6	VPS Charge Heater #2	Low NO_X Burners	incl above	incl above
	1A-F8	Vacuum Tower Heater	Low NO_X Burners	6/17/99 OAC 684	97.65
Delayed Coking Unit (DCU)	15F-100	DCU Charge Heater	Low NOx burner	9/30/1997 OAC 628	124.0
Hydrotreater Unit #1 (HTU1)	7C-F4	HTU1 Charge Heater	Low NOx burner	7/16/1990 OAC 286	240.00
	7C-F5	HTU1 Fractionator Reboiler	Low NOx burner	incl above	incl above
Hydrotreater Unit #2 (HTU2)	11H-102	HTU2 Stripper Reboiler	Low NOx Burners	10/16/1997 OAC 630	241.00
	11H-103	HTU2 Fractionator Reboiler	Low NOx Burners	incl above	incl above
Catalytic Reforming Unit #2 (CRU2)	10H-101	CRU2 Charge Heater	None		60.52
	10H-102	CRU2 Interheater #1	None		55.28
	10H-104	CRU2 Stabilizer Reboiler	None		50.54
Boiler House (BOHO)	ECB1	Erie City Boiler #1	None		390 MMBtu/hr (6 burners @ 65 each)
Cogen	GTG1	GTG HRSG w/ duct burners	SCR	10/26/1990 OAC 475	163 MMBtu/hr
	GTG2	GTG HRSG w/ duct burners	SCR	incl above	163 MMBtu/hr
	GTG3	GTG HRSG w/ duct burners	SCR	8/7/1991 OAC 476	163 MMBtu/hr

Shell has determined that the last year (2019) of emissions is representative of the anticipated actual emissions for the near future, and thus serves as an appropriate baseline for the purposes of this four-factor analysis. There are no anticipated changes to production rates or equipment that would result in a different set of emissions being necessary for appropriate analysis of potential emissions reduction options for the PSR. The baseline emissions are consistent with reported emissions for 2019, and they are summarized in Tables 4-1 and 4-2, below.

Table 4-1. Baseline Emissions Summary - All Applicable Units

Pollutant	Baseline Emissions (tons)
NO_X	592.6
SO_2	13.5
PM_{10}	35.4
NH_3	4.5
H_2SO_4	0.09

Table 4-2. Baseline Emissions Summary - Individual Units

Process Area	Emission Unit	Unit Description	Baseline Emissions (tons)				
			NO_X	SO_2	PM_{10}	H_2SO_4	NH_3
	1A-F5	VPS Charge Heater #1	77.6	3.5	8.0	0.03	N/A
Vacuum Pipe Still (VPS)	1A-F6	VPS Charge Heater #2	Included with 1A-F5				
	1A-F8	Vacuum Tower Heater	12.4	1.2	2.7	0.01	N/A
Delayed Coking Unit (DCU)	15F-100	DCU Charge Heater	21.0	1.1	2.4	0.01	N/A
Hydrotreater Unit #1 (HTU1)	7C-F4	HTU1 Charge Heater	39.4	3.0	4.3	0.002	N/A
	7C-F5	HTU1 Fractionator Reboiler	Included with 7C-F4				
Hydrotreater Unit #2 (HTU2)	11H-102	HTU2 Stripper Reboiler	18.5	0.2	3.7	0.002	N/A
	11H-103	HTU2 Fractionator Reboiler	Included with 11H-102				
	10H-101	CRU2 Charge Heater	65.3	0.2	3.6	0.002	N/A
Catalytic Reforming Unit #2 (CRU2)	10H-102	CRU2 Interheater #1	Included with 10H-101				
	10H-103 [a]	CRU2 Interheater #2	Included with 10H-101				
	10H-104	CRU2 Stabilizer Reboiler	21.0	0.1	1.2	0.001	N/A
Boiler House (BOHO)	ECB1	Erie City Boiler #1	182.4	1.7	3.5	0.01	N/A
	GTG1	GTG HRSG w/ duct burners	155.0	2.6	6.0	0.02	4.50
Cogen	GTG2	GTG HRSG w/ duct burners	Included with GTG1				
	GTG3	GTG HRSG w/ duct burners	Included with GTG1				

[a] The CRU2 Interheater #2, unit 10H-103, is not an emission unit subject to the four-factor analysis, as the heat input is less than 40 MMBtu/hr. For the purposes of evaluating tail-end controls (such as post-combustion NO_X control via SCR) it is included in the analysis because it routes to a shared stack with 10H-101 and 10H-102, and thus must be taken into account for the additional exhaust flow and emissions when scaling control cost calculations.

5. NO_X FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

In order to minimize NO_X emissions from a combustion unit, controls can take the form of either combustion or post-combustion methods. Low-NO_X burners (LNB) work to limit NO_X formation during combustion, using various methods to reduce peak flame temperature and increase flame length. Selective catalytic reduction (SCR) addresses NO_X emissions post-combustion, using catalyst and reagent to convert NO_X to elemental nitrogen before emissions leave the stack. Both controls are explained in more detail below. Good combustion practices are also described, as they represent the current emissions reduction method for several of the burners and heaters at the refinery.

5.1.1. Combustion Controls

5.1.1.1. Low-NO_X Burners (LNB)

LNB are the most widely used NO_X control devices for refinery process heaters today. Different burner manufactures use different burner designs to achieve low NO_X emissions, but all designs essentially implement two fundamental tactics - low excess air and staged combustion. Low excess air decreases the total amount of nitrogen present at the burner, thereby decreasing the resulting thermal NO_X formation. Staged combustion burns fuel in two or more steps. The primary combustion zone is fuel-rich and the secondary zones are fuel-lean. Using these tactics, LNBs inhibit thermal NO_X formation by controlling the flame temperature and the fuel/air mixture within the flame burner zone.

5.1.1.2. Good Combustion Practices

NO_X emissions can be controlled by maintaining various operational combustion parameters. These operational methods can include staged fuel combustion, staged air combustion, and low excess air combustion. The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. This is an appropriate control option for small heaters in which emissions are considered to be de minimis, and the implementation of good combustion practices at the Puget Sound Refinery meets the requirements of the Reasonable Available Control Technology (RACT) program. Good combustion practices are the selected control option for several emission units found in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. The programs represented in the RBLC database have requirements that are more stringent than those of the regional haze program, including consent decrees and the Prevention of Significant Deterioration Best Available Control Technology (PSD BACT) program. The detailed RBLC database search results are included in Appendix A of this report.

5.1.2. Post Combustion Controls

5.1.2.1. Selective Catalytic Reduction (SCR)

SCR is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[3] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1. Combustion Controls

5.2.1.1. Low-NO_X Burners

Burner design, operating conditions, and surrounding equipment can heavily influence technical feasibility for burner retrofits. The only units that do not feature a LNB are the Catalytic Reforming Unit #2 charge heater, interheater #1, and stabilizer reboiler. LNB will only be considered for these units going forward.

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[3] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

For the purposes of this four-factor analysis, it is assumed that LNBs are technically feasible. Costs presented in this report are determined based on installations of similar burner retrofits at the refinery, but it is important to note that actual costs could be substantially higher for a given unit if additional changes are required for the process based on heater footprint constraints, current burner arrangement, or process flow challenges. These technical challenges could also result in a burner retrofit that is not technically feasible for a given unit; however, the control is not eliminated from this analysis on the basis of technically infeasibility for any of the four units not currently using this technology (more efficient means of control).

5.2.1.2. Good Combustion Practices

Good combustion practices are currently employed for all burners and heaters, and are therefore considered technically feasible for the facility. Good combustion practices are considered the baseline emissions reduction method for this analysis, and all emissions reductions estimates use this control as a baseline.

5.2.2. Post Combustion Controls

5.2.2.1. Selective Catalytic Reduction

SCR is a widely accepted emissions control technology for heaters and burners in the industry. While specific circumstances such as exhaust temperature can result in SCR implementation challenges or even infeasibility for a given unit, the technology more broadly is considered technically feasible. In the case of the Cogen GTG units, SCR was already installed in 1990 and 1991. This is the most stringent of the controls Ecology requested a four-factor analysis for; therefore, no additional controls will be evaluated for the Cogen GTG units. For the remaining emission units, SCR is not eliminated on the basis of technical infeasibility for the purposes of this analysis.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

The effectiveness of LNBs vary from unit to unit – control cost calculations are calculated on the basis of an anticipated NO_X emission factor on a lb NO_X per million Btu's basis (lb/MMBtu). The effiencies are summarized in Table 5-1, below. Detailed cost calculations are provided in Appendix B of this report.

Table 5-1. Summary of Emissions Reduction Effectiveness

Emissions Reduction Method	Control Efficiency
Selective Catalytic Reduction (SCR) [1]	90%
Low-NO_X Burners (LNB) [2]	48-81%
Good Combustion Practices	Baseline

[1] SCR control efficiency, for the purposes of the cost calculations and four-factor analysis, is assumed to be 90% based on data provided in the EPA Control Technology Fact Sheet for SCR.
https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
The use of this control efficiency is a conservative approximation, and testing would be required on a unit-by-unit basis to determine what level of control is attainable, particularly given concerns of ammonia slip that can result in impacts counter to the goals of the regional haze program.

[2] LNB control effiency is calculated by comparing baseline emission levels to an anticipated controlled NO_X emission rate of 0.06 lb NO_X/MMBtu of heat input. This controlled NO_X emission rate is obtained from LNB installations for different units at the Puget Sound Refinery.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the four factors listed below:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

5.4.1.1. Selective Catalytic Reduction Cost Calculations

SCR cost calculations are developed using the EPA Control Cost Manual. Where applicable, site- or location-specific values are used for the various inputs to the control cost methodology. The emission units that share the same stack are calculated as if one SCR system would apply to all units emitting to the same stack.

Costs are converted to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). A retrofit factor of 1.5 applied to the capital cost estimates, consistent with the EPA Control Cost Manual. This retrofit factor accounts for the additional engineering involved with changes to the heater or boiler, such as altering fan capacity, changes to furnace geometry, and adding systems to the process flow to allow for better control and stabilization of stream conditions like temperature. An interest rate of 7% is used for developing annualized capital costs. Details for the selection of 7% as the interest rate are included in Appendix B.

SCR cost calculations are summarized in Table 5-2. Detailed cost calculations are included in Appendix B.

Table 5-2. Summary of SCR Cost Calculations

Unit ID	Annual Cost ($/year) [1]	Emissions Reduced (tons/year)	Cost Effectiveness ($/ton)
1A-F5	$1,390,240	69.8	$19,906
1A-F6	Included with 1A-F5		
1A-F8	$508,816	11.2	$45,593
15F-100	$583,237	18.9	$30,859
7C-F4	$911,082	35.5	$25,693
7C-F5	Included with 7C-F4		
11H-102	$887,257	16.7	$53,289
11H-103	Included with 11H-103		
10H-101	$705,805	58.8	$12,010
10H-102	Included with 10H-101		
10H-104	$317,756	18.90	$16,813
ECB1	$2,097,013	164.2	$12,774

[1] Cost calculations are preliminary, and unit-specific engineering will be required to determine technical feasibility and cost of implementation. Additional engineering is expected to result in substantial additional control costs that cannot be quantified based on currently available information about modifications needed at these units.

5.4.1.2. Low-NO_X Burner Cost Calculations

LNB cost calculations are developed based on historical vendor data and installation costs for other units at the Puget Sound Refinery that do not currently have LNBs. The ability and complexity involved with installing low-NOx burners on a heater or boiler depends on many unit-specific characteristics. Because a full engineering review has not been conducted for these units, these control costs do not include the full engineering and heater or boiler modification costs that may be required to implement low-NOx burners on these specific units. These costs should be considered the minimal end of the range of costs that may be necessary to implement low-NOx burners on the units addressed in this analysis. Costs are then scaled by rated heat input and adjusted to 2018 dollars using the CEPCI.[4] It should be emphasized that costs and technical feasibility for low-NO_X burner implementations can vary considerably from one heater or boiler to another. Unit-specific engineering would be required prior to any low-NO_X burner implementation and may indicate substantial additional control costs.

LNB cost calculations are summarized in Table 5-3, and the detailed cost calculations are included in Appendix B.

Table 5-3. Summary of LNB Cost Calculations

Unit ID	Annual Cost ($/year) [1]	Emissions Reduced (tons/year)	Cost Effectiveness ($/ton)
10H-101	$47,377	17.18	$2,758
10H-102	$45,735	22.85	$2,002
10H-104	$44,196	10.15	$4,354
ECB1	$171,756	147.31	$1,166

[1] Cost calculations are preliminary, and unit-specific engineering will be required to determine technical feasibility and cost of implementation. Additional engineering is expected to result in substantial additional control costs that cannot be quantified based on currently available information about modifications needed at these units.

5.4.2. Timing for Compliance

Shell believes that reasonable progress compliant controls (good combustion practices, LNB for 8 units, and SCR for 3) are already in place. However, if Ecology determines that one of the NO_X reduction options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period). Any changes to heaters or boilers at the refinery would need to be incorporated into the schedule of a future refinery turnaround. Refinery turnarounds are infrequent and complex undertakings that require several years of advance planning.

5.4.3. Energy Impacts and Non-Air Quality Impacts

The cost of energy required to operate SCR has been included in the cost analyses found in Appendix B. To operate the SCR, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Reheating the flue gas, as necessary, for SCR application would also require substantial natural gas usage with an associated increase in direct emissions. The use of NO_X reduction methods that incorporate ammonia injection like SCR leads to increased health risks to the local

[4] Costs are scaled by the ratio of the maximum rated heat input to the rated heat input of the unit evaluated in the vendor quotes and installation costs using an exponent of 0.6.

community from ammonia slip emissions. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse health impacts.

5.4.4. Remaining Useful Life

The remaining useful life of the ECB1 is expected to be short enough to impact the feasibility and cost of implementing NO_X control technologies. In the relatively near future, substantial upgrades will be required to replace the boiler's refractory and the boiler skin. The remaining useful life of the unit is expected to be less than 10 years – for the purposes of this analysis and the cost calculations the remaining useful life is assumed to be 8 years. The remaining useful life for all remaining units evaluated in this analysis is at least 20 years, and thus is not considered to have an impact on the feasibility or applicability of either emissions reduction option being considered.

5.5. NO_X CONCLUSION

Shell assumes that SCR is technically feasible for the units evaluated in this report for the purpose of this analysis. SCR cost calculations are developed using the EPA Control Cost Manual. Where applicable, site- and unit-specific values are used for process variables or costs. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

For the purposes of this analysis, LNB costs are developed for low-NO_X burners. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including unit footprint, downstream process units, and flow conditions, there are potentially engineering constraints. While Shell has not ruled out LNB retrofits on the basis of technical feasibility in this analysis, it is important to note that a more thorough, unit-specific evaluation by vendors will be required to determine if the installation of low-NO_X is technically feasible. LNB cost-effectiveness metrics are lower than those of SCR. In the case of both LNB and SCR cost estimates, additional unit-specific engineering has the potential to add substantial additional costs. Shell concludes that the existing emissions reduction method of good combustion practice is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.

6. PM_{10}, SO_2, NH_3, AND H_2SO_4 EVALUATION

Per Ecology's direction, the only emissions controls being evaluated for a complete four-factor analysis are SCR and low-NO_X burners for NO_X emissions control. The following section is provided for completeness to address the initial four-factor analysis request for PM_{10}, SO_2, NH_3, and H_2SO_4. This section of the report provides a qualitative assessment of the four additional pollutants other than NO_X, with conclusions consistent with Ecology's direction that a detailed analysis of these pollutants is not necessary for these pollutants.

The baseline emission rates for PM_{10}, SO_2, NH_3, and H_2SO_4 are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

The U.S. EPA's RBLC database and historic BACT reports for the facility were searched to identify possible control technologies that could be used to reduce PM_{10}, SO_2, NH_3, and H_2SO_4 emissions from applicable units for regional haze at the Puget Sound Refinery. To ensure all potentially relevant control methodologies are considered, the search was conducted both for combustion units less than 100 MMBtu/hr of heat input and combustion units with a heat input between 100 and 250 MMBtu/hr.

In the case of PM_{10} and H_2SO_4, the RBLC results included only good combustion practices for emissions controls. This is consistent with current practices at the Puget Sound Refinery, and Shell concludes that no additional controls or emission reduction measures are necessary for the PSR.

For SO_2 entries in the RBLC database, the control technologies likewise included combustion practices, with the use of low-sulfur fuels for combustion also included. CEMS are currently used to monitor inlet fuel sulfur content to ensure compliance with the low-sulfur fuel requirements of NSPS Subpart J or BACT permit limits for units sharing the same fuel gas system. Good combustion practices and the use of low-sulfur fuels are consistent with current practices at the Puget Sound Refinery, and no additional emissions reductions options are required to maintain practices consistent with those found in the RBLC database.

Finally, for NH_3 there are currently no appreciable NH_3 emissions from the units currently evaluated for the four-factor analysis, other than from the use of SCR at the Cogen GTGs. Should emissions controls be installed that involve the use of ammonia at other heaters or boilers, then there is the potential for ammonia slip to result. No additional emission reduction measures are appropriate at this time.

No additional control measures were identified as appropriate for the process heaters and boilers applicable to regional haze at this facility. Therefore, no additional controls or emission reduction options are evaluated for PM_{10}, SO_2, NH_3, and H_2SO_4 in this analysis.

APPENDIX A : RBLC SEARCH RESULTS

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	umber 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx anual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx anual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Table B-1. SCR Cost Calculation Summary

Unit ID	Annual Cost ($/year)	Emissions Reduced (tons/year)	Cost Effectiveness ($/ton)
1A-F5	$1,390,240	69.8	$19,906
1A-F6	Incl. Above	Incl. Above	Incl. Above
1A-F8	$508,816	11.2	$45,593
15F-100	$583,237	18.9	$30,859
7C-F4	$911,082	35.5	$25,693
7C-F5	Incl. Above	Incl. Above	Incl. Above
11H-102	$887,257	16.7	$53,289
11H-103	Incl. Above	Incl. Above	Incl. Above
10H-101	$705,805	58.8	$12,010
10H-102	Incl. Above	Incl. Above	Incl. Above
10H-104	$317,756	18.9	$16,813
ECB1	$2,097,013	164.2	$12,774

Cost Estimate

Shell Puget Sound Refinery: 1A-F5 and 1A-F6

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) =	$11,891,419	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$157,938	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,125,891	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,283,830	in 2019 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 =	$59,457	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$7,327	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$52,843	in 2019 dollars
Annual Catalyst Replacement Cost =		$38,311	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$157,938	in 2019 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) =	$3,341	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,122,550	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,125,891	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,283,830	per year in 2019 dollars
NOx Removed =	70	tons/year
Cost Effectiveness =	$18,382	per ton of NOx removed in 2019 dollars

Table B-2. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	41,510	scfm
	58,923	acfm
Baghouse Outlet Temperature	278	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	17,415.0	lb/hr
Heat Input Required [2]	92.9	Btu/lb
	1.6	MMBtu/hr
	14,175	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$106,410	$/year
Adjusted Cost Effectiveness	$19,906	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant:

0.730 $atm\text{-}ft^3/lbmol\text{-}R$

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from
https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 1A-F8

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) =	$4,642,901	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$50,831	in 2019 dollars
Indirect Annual Costs (IDAC) =	$441,196	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$492,028	in 2019 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 =	$23,215	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,171	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$17,535	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$8,911	in 2019 dollars
Direct Annual Cost =		$50,831	in 2019 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) =	$2,907	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$438,290	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$441,196	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$492,028	per year in 2019 dollars
NOx Removed =	11	tons/year
Cost Effectiveness =	$44,089	per ton of NOx removed in 2019 dollars

Table B-3. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	13,766	scfm
	23,423	acfm
Baghouse Outlet Temperature	425	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	4,533.3	lb/hr
Heat Input Required [2]	56.3	Btu/lb
	0.3	MMBtu/hr
	2,236	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$16,788	$/year
Adjusted Cost Effectiveness	$45,593	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant: 0.730 atm-ft^3/lbmol-R

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from
https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 15F-100

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) =	$5,422,837	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$55,463	in 2019 dollars
Indirect Annual Costs (IDAC) =	$514,869	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$570,332	in 2019 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 =	$27,114	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,983	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$14,930	in 2019 dollars
Annual Catalyst Replacement Cost =		$11,437	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$55,463	in 2019 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) =	$2,953	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$511,916	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$514,869	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$570,332	per year in 2019 dollars
NOx Removed =	19	tons/year
Cost Effectiveness =	$30,176	per ton of NOx removed in 2019 dollars

Table B-4. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	12,677	scfm
	22,312	acfm
Baghouse Outlet Temperature	455	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	4,029.1	lb/hr
Heat Input Required [2]	48.7	Btu/lb
	0.2	MMBtu/hr
	1,719	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$12,904	$/year
Adjusted Cost Effectiveness	$30,859	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant: 0.730 atm-ft^3/lbmol-R

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 7C-F4 and 7C-F5

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) =	$8,329,899	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$93,833	in 2019 dollars
Indirect Annual Costs (IDAC) =	$789,470	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$883,304	in 2019 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 =	$41,649	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$3,720	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$26,298	in 2019 dollars
Annual Catalyst Replacement Cost =		$22,166	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$93,833	in 2019 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) =	$3,128	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$786,342	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$789,470	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$883,304	per year in 2019 dollars
NOx Removed =	35	tons/year
Cost Effectiveness =	$24,910	per ton of NOx removed in 2019 dollars

Table B-5. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	20,773	scfm
	34,680	acfm
Baghouse Outlet Temperature	408	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	6,985.7	lb/hr
Heat Input Required [2]	60.5	Btu/lb
	0.4	MMBtu/hr
	3,700	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$27,779	$/year
Adjusted Cost Effectiveness	$25,693	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant: 0.730 $atm\text{-}ft^3/lbmol\text{-}R$

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 11H-102 and 11H-103

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) =	$8,352,443	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$89,430 in 2019 dollars
Indirect Annual Costs (IDAC) =	$791,600 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$881,030 in 2019 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 =	$41,762 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,747 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$23,906 in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$22,016 in 2019 dollars
Direct Annual Cost =		$89,430 in 2019 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) =	$3,129 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$788,471 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$791,600 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$881,030 per year in 2019 dollars
NOx Removed =	17 tons/year
Cost Effectiveness =	$52,915 per ton of NOx removed in 2019 dollars

Table B-6. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	19,688	scfm
	39,462	acfm
Baghouse Outlet Temperature	582	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	5,571.5	lb/hr
Heat Input Required [2]	17.0	Btu/lb
	0.1	MMBtu/hr
	830	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$6,227	$/year
Adjusted Cost Effectiveness	$53,289	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant:

0.730 $atm\text{-}ft^3/lbmol\text{-}R$

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from
https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 10H-101 and 10H-102

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) =	$5,939,772	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$71,782	in 2019 dollars
Indirect Annual Costs (IDAC) =	$563,699	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$635,480	in 2019 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 =	$29,699	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$6,165	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$22,464	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$13,454	in 2019 dollars
Direct Annual Cost =		$71,782	in 2019 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) =	$2,984	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$560,714	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$563,699	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$635,480	per year in 2019 dollars
NOx Removed =	59	tons/year
Cost Effectiveness =	$10,813	per ton of NOx removed in 2019 dollars

Table B-7. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	18,980	scfm
	24,349	acfm
Baghouse Outlet Temperature	207	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	9,664.7	lb/hr
Heat Input Required [2]	110.6	Btu/lb
	1.1	MMBtu/hr
	9,368	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$70,325	$/year
Adjusted Cost Effectiveness	$12,010	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant: 0.730 atm-ft^3/lbmol-R

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Cost Estimate

Shell Puget Sound Refinery: 10H-104

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) =	$3,026,162	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$29,277	in 2019 dollars
Indirect Annual Costs (IDAC) =	$288,479	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$317,756	in 2019 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 =	$15,131	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,983	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$7,401	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$4,762	in 2019 dollars
Direct Annual Cost =		$29,277	in 2019 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) =	$2,810	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$285,670	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$288,479	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$317,756	per year in 2019 dollars
NOx Removed =	19	tons/year
Cost Effectiveness =	$16,813	per ton of NOx removed in 2019 dollars

Cost Estimate

Shell Puget Sound Refinery: ECB1

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) =	$11,420,745	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$137,600	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,916,288	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,053,888	in 2019 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 =	$57,104	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$17,221	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$23,935	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$39,340	in 2019 dollars
Direct Annual Cost =		$137,600	in 2019 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) =	$3,313	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,912,975	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,916,288	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,053,888	per year in 2019 dollars
NOx Removed =	164	tons/year
Cost Effectiveness =	$12,511	per ton of NOx removed in 2019 dollars

Table B-8. Cost Calculation for Heating Exhaust for SCR

Variable	Value	Unit
Baghouse Outlet Airflow [1]	18,341	scfm
	26,657	acfm
Baghouse Outlet Temperature	296	F
SCR Inlet Temperature	650	F
SCR Inlet Flow Rate [1]	7,409.0	lb/hr
Heat Input Required [2]	88.5	Btu/lb
	0.7	MMBtu/hr
	5,745	MMBtu/year
Natural Gas Cost	$7.51	$/MMBtu
Annual Cost to Reheat Stream	$43,126	$/year
Adjusted Cost Effectiveness	$12,774	$/ton

[1] Assumes Ideal Gas Law. Conversions use gas constant: 0.730 atm-ft^3/lbmol-R

[2] Average heat capacity of air: 0.250 Btu/lb-F
Obtained from https://www.ohio.edu/mechanical/thermo/property_tables/air/air_Cp_Cv.html

[3] Natural gas price and higher heating value obtained from the Energy Information Administration. Natural Gas Prices for Industrial Sources in Washington, January 2020.
https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SWA_m.htm.
Heat Content of Natural Gas Consumed in Washington, 2019.
https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

Natural Gas Cost:	8.04	$/mcf
Natural Gas HHV:	1071	Btu/cf

Table B-9. LNB Input Data

Variable	Value				Unit
Unit ID	10H-101	10H-102	10H-104	ECB1	
Maximum Heat Input Rate [1]	60.52	55.28	50.54	390	MMBtu/hr
Baseline NO_X Emission Rate [1]	28.03	37.27	21.00	182.40	tons/year
Fuel HHV [2]	1,189	1,189	1,189	1,189	Btu/scf
Actual Annual Fuel Consumption [1]	303,944,431	404,257,767	304,067,224	983,326,805	scf/year
Days of Operation	365	365	365	365	days/year
Low NO_X Emissions [3]	0.060	0.060	0.060	0.060	lb/MMBtu
	10.845	14.425	10.850	35.087	tons/year
Control Efficiency	61%	61%	48%	81%	
Interest Rate [4]	7.00%	7.00%	7.00%	7.00%	
Estimated Equipment Life	20	20	20	8	years
Chemical Engineering Plant Cost Index					
2019	607.5	607.5	607.5	607.5	
2006	499.6	499.6	499.6	499.6	

[1] Site-Specific value for the Shell Puget Sound Refinery

[2] Default value provided in the EPA's Control Cost Manual and associated template calculation workbook for various control technologies.

[3] LNB Emission rates based on other retrofits at the Shell Puget Sound Refinery.

[4] See "Note on the Interest Rate Used in Cost-Effectiveness Calculations" in Appendix B of the report.

Table B-10. LNB Direct Capital Costs

Cost	10H-101	10H-102	10H-104	ECB1	Notation [1]
Purchased Equipment Costs [2]					
Low-NO_X Burner Unit	$134,231	$127,132	$120,475	$410,538	A
Instrumentation	Incl.	Incl.	Incl.	Incl.	0.1 * A
Sales Tax	$4,026.94	$3,813.97	$3,614.24	$12,316.14	0.03 * A
Freight	$6,711.57	$6,356.61	$6,023.73	$20,526.90	0.05 * A
Subtotal, Purchased Equipment Cost	$144,970	$137,303	$130,113	$443,381	PEC
Direct Installation Costs [2]	$100,000	$100,000	$100,000	$100,000	DI
Total Direct Cost	**$244,970**	**$237,303**	**$230,113**	**$543,381**	DC = PEC + DI

[1] Direct capital costs developed using methods consistent with the "OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

[2] Cost calculations are preliminary, and unit-specific engineering will be required to determine technical feasibility and cost of implementation. Additional engineering is expected to result in substantial additional control costs that cannot be quantified based on currently available information about modifications needed at these units. LNB capital and installation costs based on project costs for the Vacuum Pipe Still Gas Oil Tower (Unit ID 1A-F4) in 2006. Costs are provided in 2006$ and scaled using maximum heat inputs and a scaling factor of 0.6 with the following maximum heat inputs:

Heat Input for Original Unit	200	200	200	200	MMBtu/hr
Heat Input for Each Unit	60.52	55.28	50.54	390	MMBtu/hr

Table B-11. LNB Indirect Capital Costs

Cost	10H-101	10H-102	10H-104	ECB1	Notation
Overhead & Contingencies					
Engineering	$14,497	$13,730	$13,011	$44,338	0.1 * PEC
Construction & Field Expenses	$7,248	$6,865	$6,506	$22,169	0.05 * PEC
See "Note on the Interest Rate Used in Cost-Effectiven	$14,497	$13,730	$13,011	$44,338	0.1 * PEC
Start-Up	$2,899	$2,746	$2,602	$8,868	0.02 * PEC
Performance Testing	$1,450	$1,373	$1,301	$4,434	0.01 * PEC
Contingencies	$4,349	$4,119	$3,903	$13,301	0.03 * PEC
Total Indirect Cost	**$44,941**	**$42,564**	**$40,335**	**$137,448**	

[1] Indirect installation costs developed using methods consistent with the "OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

Total Capital Investment (TCI) (2006 $)	**$289,911**	**$279,867**	**$270,448**	**$680,829**

Table B-12. LNB Direct Annual Costs

Variable	Value				Units
Hours per Year	8760	8760	8760	8760	hours
Operating Labor	N/A	N/A	N/A	N/A	
Maintenance	N/A	N/A	N/A	N/A	
Total Direct Annual Costs (2006 $)	**$0**	**$0**	**$0**	**$0**	

Table B-13. LNB Indirect Annual Costs

Cost	10H-101	10H-102	10H-104	ECB1	Notation
Administrative Charges	$5,798	$5,597	$5,409	$13,617	0.02 * TCI
Insurance	$2,899	$2,799	$2,704	$6,808	0.01 * TCI
Property Tax	$2,899	$2,799	$2,704	$6,808	0.01 * TCI
Capital Recovery	$27,366	$26,417	$25,528	$114,017	CRF * TCI
Total Indirect Annual Cost (2006 $)	**$38,962**	**$37,612**	**$36,346**	**$141,250**	

Table B-14. LNB Cost Summary

Variable	10H-101	10H-102	10H-104	ECB1	Units
Total Annualized Cost	$47,377	$45,735	$44,196	$171,756	2019$/year
Emission Rate Prior to Burner Replacement	28.03	37.27	21.00	182.40	tons NO_X/yr
Pollutant Removed	17.18	22.85	10.15	147.31	tons NO_X/yr
Cost Per Ton of Pollutant Removed	$2,758	$2,002	$4,354	$1,166	$/ton

A Note on the Interest Rate Used in Cost-Effectiveness Calculations

The cost analyses in this report follow OMB's guidance by using an interest rate of 7% for evaluating the cost of capital recovery, as discussed below.

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[5]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[6] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[7] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%. "As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."[8]

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[5] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[6] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[7] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[8] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

Tesoro Refining & Marketing Company LLC
P. O. Box 700
Anacortes, WA 98221

April 29, 2020

Chris Hanlon-Meyer
Air Quality Program
Washington State Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

RE: Regional Haze 4-Factors Analysis - Tesoro's Response to 4-Factor Information Request

Dear Mr. Hanlon-Meyer:

We are writing in response to the Washington Department of Ecology's ("Ecology") letter dated November 27, 2019, in which Ecology asks Tesoro Refining & Marketing Company LLC's Anacortes Refinery (d/b/a "Marathon Anacortes Refinery") to provide information to support a 4-Factor Analysis of potential emission control retrofit projects for inclusion in Washington State's long-term strategy to meet Regional Haze Program reasonable progress goals at Class 1 Areas. Ecology's letter requests analysis in terms of the four statutory factors from the Regional Haze Rule (cited at 40 CFR §51.308(d)) which are, as follows:

- Factor #1 – cost of compliance;
- Factor #2 – time necessary for compliance;
- Factor #3 – energy and non-air quality environmental impacts of compliance; and
- Factor #4 – remaining useful life on existing source subject to such requirements.

Ecology's letter requests supporting information for each fluid catalytic cracking unit (FCCU) and boiler and heater greater than 40 MMBtu/hr that has not been retrofitted since 2005. A subsequent email from, Chris Hanlon-Meyer at Ecology to Bob Poole of the Western States Petroleum Association (WSPA) on March 9, 2020 narrowed the control cost analysis scope at refineries to consideration of only Low-NOx burners and selective catalytic reduction (SCR). On April 10th, Mr. Hanlon granted an extension request to provide information from March 31st to April 30, 2020.

The attached timely report provides the requested information. As the enclosed demonstrates, additional NOx control technologies are not supported for the FCCU, COBs, process heaters or boilers at the Anacortes Refinery.

Please contact Lester Keel at (360) 293-1601 should you have any questions regarding this response.

Sincerely,

Paul Zawila
ES&S Manager, Marathon Anacortes Refinery

CC: Paul Zawila
Gregg Stiglic
Lester Keel

Regional Haze Four-Factor Analysis for NO_x Emissions

FCCU and Heaters and Boilers Greater than 40 MMBtu/hr

Prepared for
Tesoro Refining & Marketing Company LLC
Anacortes Refinery

April 28, 2020

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Regional Haze Four-Factor Analysis for NOx Emissions

April 28, 2020

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Abbreviations

AOP	air operating permit
BART	best available retrofit technology
CO	carbon monoxide
COB	carbon monoxide boiler
EPA	Environmental Protection Agency
FCCU	fluid catalytic cracking unit
H_2SO_4	sulfuric acid
IFGR	internal flue gas recirculation
LNB	low-NOx burners
NH_3	ammonia
NOx	nitrogen oxides
O&M	operating and maintenance
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
RACT	reasonably available control technology
RFG	refinery fuel gas
RHR	Regional Haze Rule
SCR	selective catalytic reduction
SIP	state implementation plan
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SWS	sour water stripper
tpy	ton per year
ULNB	ultra-low-NOx burner
WGS	wet gas scrubber
WSPA	Western States Petroleum Association

1.0 Introduction

The Regional Haze Rule (RHR),[1] published on July 15, 2005, by the U.S. Environmental Protection Agency (EPA), defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of state implementation plans (SIPs) in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory federal Class I areas. The original state SIPs were due on December 17, 2007, and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. As part of the second RHR planning period, states are required to develop and submit their updated state SIPs to EPA by July 31, 2021.

In 2007, Tesoro Refining & Marketing Company LLC's (Tesoro's) Anacortes Refinery submitted its BART analysis to the Washington Department of Ecology (Ecology) that evaluated nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate matter (PM/PM_{fil}) control strategies.[2] For SO_2 and PM/PM_{fil}, the BART analysis ended routine use of fuel oil and required the use of refinery fuel gas (RFG) or natural gas as the primary fuel for the Crude Heater F-103. For all other BART-eligible units, the existing installed combustion or other controls met BART requirements for SO_2 and PM/PM_{fil}.[3] This BART analysis also required Ultra-Low-NOx Burners (ULNB) to be installed on F-103 for NO_x control.[4] All other BART-eligible units had existing combustion or other controls that met BART requirements for NOx. Additionally, EPA required H_2S limitations on non-BART eligible fired sources burning refinery fuel gas.[5]

On November 27, 2019, Ecology requested that Tesoro complete a "4-Factor/RACT (Reasonably Available Control Technology)" analysis (herein termed a Four-Factor analysis), for the fluid catalytic cracking unit (FCCU), and boilers and heaters greater than 40 MMBtu/hr as part of the state's regional haze reasonable progress.[6] The analysis considers the following four (4) statutory factors:

- Factor #1 – The costs of compliance;
- Factor #2 – The time necessary for compliance;

[1] The EPA also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).
[2] "Best Available Retrofit Technology Determinations Under the Federal Regional Haze Rule," Washington State Department of Ecology, June 12, 2007.
[3] "BART Determination Support Document for Tesoro Marketing and Refining Company Anacortes Refinery," Washington State Department of Ecology, February 22, 2010.
[4] Washington State Department of Ecology Final Order #7838 issued July 7, 2010.
[5] Approval and Promulgation of Implementation Plans; State of Washington; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology for Alcoa Intalco Operations, Tesoro Refining and Marketing, and Alcoa Wenatchee. 79 Fed. Reg. 33438. (June 11, 2014).
[6] November 27, 2019 letter from Chris Hanlon-Meyer of Ecology to James Tangaro of Anacortes Refinery.

- Factor #3 – The energy and non-air quality environmental impacts of compliance; and
- Factor #4 – The remaining useful life on existing source subject to such requirements

EPA issued final regional haze SIP guidance on August 20, 2019 (2019 RH SIP Guidance).[7] This Four-Factor analysis is conducted in accordance with the four statutory factors described in the 2019 RH SIP Guidance. The 2019 RH SIP Guidance recognizes that other factors, such as visibility benefits, can affect the assessment of possible control measures. Tesoro believes that the State of Washington will develop a more robust analysis if it considers the visibility benefits of possible control measures for petroleum refineries. Tesoro continues to evaluate visibility benefits associated with possible NOx control measures internally and reserves the right to supplement this analysis with information related to visibility benefits.

In response to a request made by the Western States Petroleum Association (WSPA) on March 3, 2020, to extend the deadline for information submittal to April 30, 2020, on March 9, 2020 Ecology narrowed the scope of its November 27, 2019, request to "develop control costs related to low NOx Burners and Selective Catalytic Recovery as the two Regional Haze pollutant emission reduction technologies"[8] and extended the time to provide information from March 31 to April 15, 2020. Following the onset of the COVID-19 pandemic, WSPA requested on March 23, 2020, to extend the deadline to April 30, 2020, because of the severe impacts on refinery and vendor resources. Ecology granted the request for a further extension on April 10, 2020.[9]

Provided herein is Tesoro's timely response to Ecology's request for information for a Four-Factor analysis. This report describes the background and analysis for conducting a Four-Factor analysis for low-NOx burners/ultra-low-NOx burners (LNB/ULNB) and selective catalytic reduction (SCR).

[7] "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 29, 2019. Accessed at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[8] Per emails from Chris Hanlon-Meyer (Ecology) to Bob Poole (WSPA) dated March 19 and 30, 2020.

[9] April 10, 2020 letter from Chris Hanlon-Meyer of Ecology to Bob Poole of WSPA.

2.0 Four-Factor Analysis Scope

2.1 Four-Factor Analysis Subject Equipment

Tesoro operates seventeen heaters and boilers that are rated larger than 40 MMBtu/hr, two carbon monoxide (CO) Boilers, and one FCCU subject to the Four-Factor Analysis as listed in Table 2-1.

Table 2-1 Four-Factor Analysis Applicability Review

Emission Unit		Nominal Capacity (MMBtu/hr)[1]	Included in Four-Factor Analysis?
F-101	Crude Heater 1	120	No - Retrofitted
F-102	Crude Heater 2	120	Yes
F-103	Crude Heater 3	132	No – Retrofitted
F-104	CGS Column C C-113 Reboiler	60	No – Retrofitted
F-201	Vacuum Flasher Heater	96	Yes
F-301	CCU Feed Heater	128	Yes
F-303	Startup Air Preheater	69	No – Startup-only
F-652	DHT Feed Heater	67	Yes
F-751	Boiler 1	268	Yes
F-752	Boiler 2	268	Yes
F-753	Boiler 3	220	Yes
F-6600	NHT Feed Heater	65	Yes
F-6601	NHT Column C-6600 Reboiler	68	Yes
F-6602	BenSat Column C-6601 Reboiler	73.5	No – Retrofitted
F-6650/1/2/3	CR Feed Heaters[2]	391	Yes
F-302	Carbon Monoxide Boiler 1	264	No - Retrofitted
F-304	Carbon Monoxide Boiler 2	322	Yes
CCU	FCCU	NA	Yes

[1] The nominal capacities listed here are not permit limits.

[2] CR Inter-Reactor Heater 3, F-6653, is only rated at 38 MMBtu per hour, but Tesoro has evaluated NOx controls for the entire combined unit denoted as F-6650/1/2/3.

Ecology stated that only emission units that had not been retrofitted with NOx controls since 2005 were subject to the Four-Factor analysis.[10] Crude Heater 1 (F-101), Crude Heater 3 (F-103), CGS Column C-113 Reboiler (F-104), BenSat Column C-6601 Reboiler (F-6602), and Carbon Monoxide Boiler 1 (F-302) have

[10] November 27, 2019 letter from Chris Hanlon-Meyer of Ecology to James Tangaro of the Anacortes Refinery.

been excluded from the Four-Factor Analysis because each of these units has been retrofitted with new burners which reduced NOx emissions since 2005.

Furnace F-303 is a startup air preheater for the FCCU, which has a capacity of 69 MMBtu/hr. F-303 operates only during the startup of the FCCU. Due to the low hours of operation and associated emissions, the evaluation of additional controls is impractical and is not included in this report. The 2019 RH SIP Guidance[11] states that it is reasonable to exclude sources from evaluation if it is clear that no additional control measures would be adopted for the source.

The remaining twelve heaters and boilers, one CO boiler, and the FCCU are subject to further evaluation for the Four-Factor Analysis.

2.2 Emissions Source Descriptions

2.2.1 FCCU COBs

The FCCU is equipped with two CO boilers, COB1 (F-302) and COB2 (F-304). F-302 was installed with the original FCCU unit in 1955, and F-304 was installed in 1964. Both COBs are critical to maintaining the overall steam balance at the refinery. The split of FCCU regenerator gas to each boiler is approximately 50/50.

F-302 is a tangentially fired, water-wall boiler that simultaneously combusts natural gas and cools flue gas via radiant heat transfer. In 2005 and 2006, F-302 was retrofitted with low-NOx burners; therefore, it is not subject to further evaluation in the Four-Factor analysis, according to Ecology's November 27, 2019 letter.[12]

F-304 operates using a standard burner design for a CO boiler. Because F-304 has not been retrofitted with NOx controls since 2005, it is included in the Four-Factor analysis.

A wet gas scrubber (WGS) was installed on the FCCU and COBs in 2005 to control emissions of SO_2, H_2SO_4, and particulate matter. This emission reduction project was recognized as being part of the original BART determination in the SIP.

2.2.2 Heaters/Boilers

A summary of process heater and boiler specifications is included in Table 2-2 below.

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[11] "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 29, 2019. Accessed at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[12] November 27, 2019 letter from Chris Hanlon-Meyer of Ecology to James Tangaro of the Anacortes Refinery.

Table 2-2 Summary of Process Heaters and Boiler Specifications

ID	Emission Unit	Year Installed	Draft Type	Air Preheat
F-102	Crude Heater	1955	Forced	Yes
F-201	Vacuum Flasher Heater	1955	Forced	Yes
F-301	CCU Feed Heater	1955	Natural	No
F-652	DHT Feed Heater	1961	Natural	No
F-751	Riley Boiler 1	1954	N/A	No
F-752	Riley Boiler 2	1954	N/A	No
F-753	Zurn Boiler	1994	N/A	No
F-6650/1/2/3	CR Heaters	1972	Natural	No
F-6600	NHT Feed Heater	1972	Natural	No
F-6601	NHT Column C-6600 Reboiler	1971	Natural	No

2.3 2014 Baseline Emissions

In the May 31, 2019 letter to Tesoro, Ecology indicated that emissions data from 2014 was used for screening major facilities for selection of sources to include in the Four-Factor analysis and that 2014 is the baseline year for the facility.[13] The actual reported emissions of NOx for the baseline year of 2014 for each of the subject units are shown below in Table 2-3.

Table 2-3 2014 Baseline Emissions of NOx

Emission Unit		NOx Emissions (ton/year)
F-102	Crude Heater 2	133
F-201	Vacuum Flasher Heater	55
F-301	CCU Feed Heater	5[A]
F-652	DHT Feed Heater	18
F-751	Boiler 1	187
F-752	Boiler 2	179
F-753	Boiler 3	23
F-6600	NHT Feed Heater	16
F-6601	NHT Column C-6600 Reboiler	17
F-6650/1/2/3	CR Feed Heater	148[A]
F-302, F-304, CCU	FCCU/CO Boilers/WGS	833
TOTAL		1,614

[A] Based on a review of 2014 emission calculations as part of this analysis, Tesoro determined that revisions to the NOx emission factors used for these heaters were appropriate based on the heater design parameters.

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[13] May 31, 2019 letter from Chris Hanlon-Meyer of Ecology to James Tangaro of Anacortes Refinery.

3.0 Technical Feasibility Analysis of Emission Control Options

According to the 2019 RH SIP Guidance,[14] only control technologies that are technically feasible are considered in the Four-Factor Analysis. Ecology narrowed the scope of its November 27, 2019, request to low-NOx burners/ultra-low-NOx burners (LNB/ULNB) and selective catalytic reduction (SCR) NOx control technologies.[15] As described in Appendix Y to 40 CFR 51, Guidelines for BART Determinations Under the Regional Haze Rule, in order to be considered available and technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions and could be applied to the source under review. The technical feasibility of LNB/ULNB and SCR are evaluated in this section for the FCCU COB2 and the process heaters and boilers identified in Section 2.0.

3.1 LNB/ULNB

LNB/ULNB reduces NO_x emissions by controlling the combustion temperature and/or the availability of oxygen. There are several designs of LNB/ULNB currently available for refinery heaters and boilers. These burners combine two NO_x reduction steps into one burner, typically staged-air with internal flue gas recirculation (IFGR) or staged-fuel with IFGR, without requiring additional external equipment. ULNB installation also requires that all tramp air be eliminated to achieve the desired NOx emissions. It is recommended to install a fuel gas filter and coalescer along with stainless steel burner piping to reduce the risk of plugging the ports of the staged fuel tips. Finally, operations will be impacted as tighter control of the excess air will be required. High excess air directly impacts the NOx emissions. Generally, ULNBs are designed for 15 to 25 percent excess air.

3.1.1 Process Heaters

The installed cost of LNBs is comparable to ULNBs for the heaters and LNBs have inferior performance; therefore, ULNBs are considered the dominant control alternative and LNBs are not evaluated further.[16] Depending on the design of the individual heater, ULNB retrofit may not be recommended because there would be a high risk of flame to tube impingement. The installation of ULNB into an existing heater increases the risk of flame impingement on the tubes and changing the heat transfer profile in the firebox. These risks were assessed by reviewing several industry-accepted variables, including flame dimensions.

Heaters F-6600 and F-6601 are considered low risk, which means no flame impingement or change in heat transfer characteristics is expected with the retrofit.

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[14] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf, page 28.

[15] Per emails from Chris Hanlon-Meyer (Ecology) to Bob Poole (WSPA) dated March 19 and 30, 2020.

[16] Dominant control alternatives are discussed in the "New Source Review Workshop Manual", October 1990, page B.41.

Heaters F-102, F-301, F-652, and F-6650/1/2/3 are at moderate risk for technical infeasibility, which means there is an increased risk of flame impingement or change in heat transfer characteristics. At a minimum, computational fluid dynamic (CFD) modeling will be required to determine the technical feasibility of retrofitting each heater. For this group of heaters, Tesoro would need to work with the burner supplier while in the conceptual phase of the project to perform CFD modeling before detailed engineering. To provide the most robust and conservative analysis, heaters with a moderate risk of technical infeasibility have been included in the Four-Factor analysis and the additional cost and time for CFD modeling has been included in the analysis. If Tesoro were to move forward with the CFD modeling and the results indicated a high risk of flame impingement or change in heat transfer characteristics, installing ULNBs on these heaters would then be considered technically infeasible.

Retrofit of Heater F-201 with ULNB is considered technically infeasible because of the risk of flame impingement and change in heat transfer characteristics due to the heater design. A ULNB in F-201 is technically infeasible because of the increased likelihood to experience a “fire cloud,” which may result in elevated NOx or elevated CO emissions or flame impingement on tube surfaces. Flame impingement can result in premature coking of tubes, shortened run lengths, and tube failures. No burner can be designed to avoid these problems due to the inherent limitations of the furnace design/furnace dimensions.

3.1.2 Boilers

LNBs were determined to be technically feasible for installation on boilers F-751 and F-752 with the removal of the air preheater and installation of an economizer. A burner upgrade would not be feasible without correcting problems with the air preheaters. The economizer will improve boiler efficiency and reduce thermal NOx formation. It will also allow a better draft profile for LNB stability. Boiler F-753 already has LNB with IFGR installed; therefore, it is not evaluated for ULNB upgrades.

3.2 SCR

SCR is a process that involves post-combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion unit exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reaction takes place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy required for the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Reduction catalysts are composed of active metals or ceramics with a highly porous structure. For the majority of commercial catalysts (metal oxides), the operating temperatures for the SCR process range from 480°F to 800°F. Proper reactor temperature is important in order to achieve high reductions in NO_x emissions. According to the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual)[17] for SCR

[17] US EPA, “EPA Air Pollution Control Cost Manual, Sixth Edition,” January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may

(updated June 2019), the NO_x removal efficiency is optimized when the temperature is approximately 700 to 750°F. Flue gas reheating may be required to achieve the optimum SCR reactor temperature for effective NO_x control.

The sulfur content of the fuel or the process exhaust stream can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in natural gas and the mercaptans used as an odorant, low concentrations of sulfur compounds in treated refinery fuel gas (RFG), and SO_2 in the FCCU/COB exhaust gases) to sulfur trioxide (SO_3). This would increase sulfuric acid mist emissions as the SO_3 also combines with water to form sulfuric acid. In addition, SO_3 and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled or may be emitted from the stack as increased emissions of PM_{10} and $PM_{2.5}$.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers have indicated they would guarantee a six-year lifespan for a SCR catalyst system to be installed at another FCCU operated by Marathon. A six-year lifespan was used in the calculations for the catalyst cost for all units.

SCR manufacturers typically estimate up to 10 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometric requirements, which necessarily results in ammonia slip. Thus, an emissions tradeoff between NO_x and ammonia occurs in high NO_x reduction applications.

SCR was determined to be technically feasible for installation on COB2 and for each of the process heaters and boilers identified in Section 2.0. SCR for boilers F-751 and F-752 is technically feasible by removing the existing air preheater and installation of an economizer to achieve the minimum inlet temperature needed for the catalyst.

3.3 Summary of Technically Feasible Control Technologies

A list of the control technologies evaluated for technical feasibility is included in Table 3-1.

be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report

Table 3-1 Technically Feasible NOx Control Technologies

Control Technology	FCCU	COB2	Heaters/Boilers
ULNB	NA	No	Yes [A]
SCR	Yes		Yes

[A] ULNB is not technically feasible for F-201, and technical feasibility must be confirmed for Heaters F-102, F-301, F-652, and F-6650/1/2/3 using CFD modeling. For purposes of this evaluation, Tesoro has assumed that retrofit of Heaters F-102, F-301, F-652, and F-6650/1/2/3 is technically feasible, but that determination may be subject to change. If Tesoro were to move forward with the CFD modeling and the results indicated a high risk of flame impingement or change in heat transfer characteristics, installing ULNBs on these heaters would then be considered technically infeasible.

4.0 Four-Factor Analysis for NOx

4.1 Four-Factor Analysis Approach

Consistent with EPA's guidance and Ecology's direction, Tesoro has completed a Four-Factor analysis for the technically feasible control options for NOx emissions following the approach described in the subsections below.

4.1.1 Factor #1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Control Cost Manual unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the control measure, referred to as "average cost-effectiveness," is compared to a cost-effectiveness threshold.

The EPA considered NOx control options up to a threshold of $3,400 per ton removed in its "Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS."[18] The cost of NOx control measures in the TSD represents nationwide average retrofit factors and equipment life. Non-electric generating units included in the TSD analysis included petroleum refinery process heaters and catalytic cracking units. The cost-effectiveness value is consistent with the range analyzed by EPA for electric generating units and in previous transport rules, including the NOx SIP call. This 2011 value of $3,400 per ton is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[19] The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost-effectiveness threshold in current dollars is calculated to be $3,430 per ton. Generally, if the average cost-effectiveness is greater than the threshold, the cost may not be considered reasonable, pending an evaluation of other factors.

The cost of an emissions control measure is derived using capital and annual O&M costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost-effectiveness value. The denominator of the cost-effectiveness value (tons of pollutant removed) is derived as the difference in 1)

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[18] "Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS; Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD." U.S. EPA. August, 2016.

[19] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to December 2019 values.

projected emissions using the current emissions control measures (baseline emissions), in tons per year (tpy), and 2) expected annual emissions performance through the installation of the additional control measure (controlled emissions), also in tpy. For purposes of calculating cost-effectiveness, Tesoro has selected 2014 as the baseline emissions year.

4.1.2 Factor #2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for the full implementation of different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the state implementation plan (SIP) by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

4.1.3 Factor #3 – Energy and Non-air Environmental Impacts:

Factor #3 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on the consideration of site-specific circumstances.

The energy impact analysis considers whether the use of emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis, energy used per ton of pollutant controlled, or total annual energy use.

4.1.4 Factor #4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life of each of the sources is assumed to be longer than the useful life of the additional emission control measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton ($/ton).

4.2 FCCU / COBs Four-Factor Analysis

4.2.1 Factor #1 Evaluation – Costs of Compliance

Tesoro has completed screening-level cost estimates for the control of NOx emissions from the FCCU and COBs. The cost estimate was developed by Tesoro's plant engineering staff, based on their considerable experience with projects at the Anacortes Refinery, with assistance from outside engineering firms. A more detailed cost estimate is likely to increase the costs of installing and implementing either of the projects.

Importantly, this initial set of cost estimates does not include additional outage time beyond a standard outage necessary to install the controls.

The cost-effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on a dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation, a 25-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5% interest is assumed in annualizing capital costs.[20]

The resulting cost-effectiveness calculations are summarized in Table 4-1. Cost summary spreadsheets are provided in Appendix A. SCR is not cost-effective for the FCCU/COBs based on the cost-effectiveness threshold of $3,430 per ton discussed in Section 4.1.1.

Table 4-1 Control Cost Summary for FCCU and CO Boilers

Unit	Control Technology	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost-Effectiveness ($/ton)
FCCU/COBs	SCR	$114,030,975	$10,747,992	747.37	$14,381

4.2.2 Factor #2 Evaluation – Time Necessary for Compliance

Any of the control measures require significant resources and time to engineer, permit, and install the equipment. Additionally, the installation must be coordinated with a planned maintenance outage because the equipment must be shut down during the installation of either ULNB or SCR. Such projects must conclude the feasibility stage of project design/justification work at least three years prior to the outage to allow time for engineering, permitting, and procurement. Permit modifications can be time-consuming and have indefinite timelines. Outage schedules are also subject to change. If the installation of controls is required through the Regional Haze process, further discussion regarding the time necessary for compliance is needed.

4.2.3 Factor #3 Evaluation – Energy and Non-Air Quality Environmental Impacts

The operation of an SCR system has significant energy requirements and negative environmental impacts. The impacts from the use of an SCR system are summarized below:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM_{10} precursor;

[20] Based on the default values in the EPA Control Cost Manual at Section 4, Chapter 2, published in 2019.

- Ammonium would combine with NOx and SO_2 to form ammonia salts, which would be emitted to the atmosphere as PM_{10};
- Sulfuric acid mist emissions will increase due to the oxidation of SO_2 to SO_3 by the SCR catalyst;
- Emissions of ammonia, ammonium sulfates, and sulfuric acid mist increase plume visibility and contribute to regional haze;
- There are safety risks associated with the transportation, handling, and storage of aqueous ammonia;
- Spent catalyst from the SCR is typically disposed of in a landfill; however, catalyst recycling or reconditioning may be available; and
- Electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power.

Tesoro has considered air quality impacts for regional haze pollutants because they are directly applicable to the goals of this analysis. Overall, there are secondary air quality impacts associated with SCR operation, which diminish some of the benefits of the NOx reductions. The associated increase in PM_{10} emissions will also increase the difficulty of obtaining an Order of Approval to Construct (or potentially a Prevention of Significant Deterioration) Permit for the installation. Ecology should consider the increased emission of PM_{10}, H_2SO_4, and NH_3 in any visibility impact analyses associated with SCR installation.

4.2.4 Factor #4 Evaluation – Remaining Useful Life

Because the Anacortes Refinery will operate for the foreseeable future, a 25-year life is used for SCR, which is the default value in the EPA Control Cost Manual. The remaining useful life of each control measure is used, as described in Section 4.1.4, to calculate emission reductions, amortized costs, and cost-effectiveness on a dollar per ton basis.

4.3 Heaters / Boilers Four-Factor Analysis

4.3.1 Factor #1 Evaluation – Costs of Compliance

Tesoro has completed screening-level cost estimates for the control of NOx emissions from the heaters and boilers using the same general methodology as described for the FCCU and COBs in Section 4.2.1. The cost estimate was developed by Tesoro's plant engineering staff and assistance by outside engineering firms. A more detailed cost estimate is likely to increase the costs of installing and implementing either of the projects. Importantly, this initial set of cost estimates does not include additional outage time beyond a standard outage necessary to install the controls.

The resulting cost-effectiveness calculations are summarized in Table 4-2 for SCR and Table 4-3 for LNB/ULNB. Cost summary spreadsheets are provided in Appendix A. Neither SCR nor LNB/ULNB are cost-effective for any process heaters or boilers based on the cost-effectiveness threshold of $3,430 per ton discussed in Section 4.1.1.

Table 4-2 Control Cost Summary for SCR for Heaters and Boilers

Emission Unit		Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
F-102	Crude Heater 2	$20,876,000	$2,021,692	125.68	$16,086
F-201	Vacuum Flasher Heater	$20,629,000	$1,813,706	51.41	$35,276
F-301	CCU Feed Heater	$18,126,000	$1,572,448	4.73	$332,721
F-652	DHT Feed Heater	$16,534,000	$1,393,396	16.45	$84,710
F-751	Boiler 1	$20,613,000	$1,798,805	178.81	$10,060
F-752	Boiler 2	$20,613,000	$1,798,740	171.10	$10,513
F-753	Boiler 3	$13,999,000	$1,249,990	15.77	$79,240
F-6600	NHT Feed Heater	$19,063,000	$1,606,331	14.00	$114,739
F-6650/1/2/3	CR Feed Heater	$30,806,000	$2,906,872	137.14	$21,196
F-6601	NHT Column C-6600 Reboiler	$18,759,000	$1,589,135	15.36	$103,459

Table 4-3 Control Cost Summary for LNB / ULNB for Heaters and Boilers

Emission Unit		Installed Capital Cost ($)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
F-102	Crude Heater 2	$5,898,000	$742,781	114.81	$6,470
F-201	Vacuum Flasher Heater	N/A[1]	N/A	N/A	N/A
F-301	CCU Feed Heater	$4,762,000	$580,961	3.36	$172,807
F-652	DHT Feed Heater	$4,506,000	$557,299	11.08	$50,296
F-751	Boiler 1	$8,972,000	$988,691	113.88	$8,682
F-752	Boiler 2	$8,972,000	$988,691	104.18	$9,491
F-753	Boiler 3	N/A[2]	N/A	N/A	N/A
F-6600	NHT Feed Heater	$4,376,000	$541,221	9.18	$58,926
F-6650/1/2/3	CR Feed Heater	$12,304,000	$1,513,750	104.70	$14,458
F-6601	NHT Column C-6600 Reboiler	$4,406,000	$544,931	10.13	$53,802

[1] LNB/ULNB retrofits are not technically feasible for F-201.

[2] F-753 Boiler 3 has a low NOx burner.

4.3.2 Factor #2 Evaluation – Time Necessary for Compliance

The time necessary for compliance is discussed in Section 4.2.2. In addition, if controls are required to be installed on more than one heater or boiler, construction schedules would need to be staggered to accommodate outages at more than one unit.

4.3.3 Factor #3 Evaluation – Energy and Non-Air Quality Environmental Impacts

The operation of an SCR system has significant energy requirements and negative environmental impacts. The impacts of an SCR system are described in Section 4.2.3. Additional negative impacts from LNB/ULNB include increased electricity consumption associated with internal flue gas recirculation.

4.3.4 Factor #4 Evaluation – Remaining Useful Life

Because the Anacortes Refinery will operate for the foreseeable future, a 25-year life is used for SCR, which is the default value in the EPA Control Cost Manual. A 20-year life is used for LNB/ULNB. The remaining useful life of each control measure is used to calculate emission reductions, amortized costs, and cost-effectiveness on a dollar per ton basis.

4.4 Projects with Potential to Reduce the Cost of Compliance

Tesoro has considered projects that have the potential to reduce the cost of compliance, as requested by Ecology.[21]

Tesoro evaluates energy efficiency projects regularly and implements those that have an economic payback. Payback is typically driven by associated production rate increases to a much greater extent than due to improved energy efficiency. Implementing energy efficiency projects to reduce the heat load to the heaters and boilers is not likely to be cost-effective in terms of this four-factor analysis. Heater firing improvements, and the resulting emission reductions, are not typically substantial (<10%), and costs are high relative to the decrease in emissions. Therefore, the refinery has concluded that energy efficiency improvement projects would be less cost-effective than the control options otherwise presented in this report.

Factor #2 in this four-factor analysis already considers the schedule to perform the work during regularly scheduled maintenance cycles and planned outages to reduce the cost of compliance.

[21] November 27, 2019 letter from Chris Hanlon-Meyer of Ecology to James Tangaro of the Anacortes Refinery.

5.0 Conclusions

At the request of Ecology, Tesoro completed a Four-Factor Analysis for the FCCU and boilers and heaters greater than 40 MMBtu/hr as part of the state's regional haze reasonable progress. The analysis identified technically feasible control technologies for NOx emissions and evaluated each of the control options for the following four statutory factors:

- Factor #1 – The costs of compliance
- Factor #2 – The time necessary for compliance
- Factor #3 – The energy and non-air quality environmental impacts of compliance
- Factor #4 – The remaining useful life on existing source subject to such requirements

For the FCCU and COBs, SCR was the only control option determined to be technically feasible. SCR is not cost-effective. SCR also has additional negative energy and non-air environmental impacts, requiring additional energy to operate the equipment and the storage and use of ammonia in the process. Based on the results of the Four-Factor Analysis, additional NOx control technologies are not supported for the FCCU and COBs at the Anacortes Refinery.

For the heaters and boilers, technical feasibility for LNB/ULNB varies by process heater. CFD modeling will be required prior to engineering to establish that it is technically feasible to install ULNB for heaters F-102, F-301, F-652, and F-6650/1/2/3, and ULNB is technically infeasible for F-201. Although SCR was determined to be technically feasible, the analysis demonstrates there are significant additional negative energy and non-air environmental impacts. Neither SCR nor LNB/ULNB is cost-effective. Based on the results of the Four-Factor Analysis, additional NOx control technologies are not supported for the process heaters and boilers at the Anacortes Refinery.

The 2019 RH SIP Guidance[22] recognizes that other factors, such as visibility benefits, can affect the assessment of possible control measures. Tesoro believes that the State of Washington will develop a more robust analysis if it considers the visibility benefits of possible control measures for petroleum refineries. Visibility benefits were not evaluated in this Four-Factor analysis, but Tesoro reserves the right to supplement this analysis with information related to visibility benefits.

[22] "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 29, 2019. Accessed at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

Appendix A

Unit Specific Screening Level Cost Summary for Control Measures

CCU - Selective Catalytic Reduction (SCR)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$114,030,975	Engineering estimate from similar installation (see Note A)
Direct Operating Costs			
Electricity		$209,997	7000 MWh/yr x $ 30.00 $/MW-hr per engineering estimate from similar installation (see note B)
Reagent (ammonia)		$1,340,590	340 lb/hr x $ 900.00 $/ton per EPA methodology (see note C)
Maintenance and operation		$570,155	0.005 x TCI per EPA methodology
Catalyst replacement		$116,845	per EPA methodology with catalyst volume estimated from similar installation (see Note D
Total Direct Operating Costs		$2,237,587	
Indirect Operating Costs			
Administrative Charges		$9,470	per EPA Methodology (see Note E)
Capital Recovery	0.0745	$8,500,935	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 25 year life			
Total Indirect Operating Costs		$8,510,405	
Total Annual Cost		**$10,747,992**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (Note F) (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	833.10	89.7%	85.73	747.37	$14,381	Controlled emissions based on 20 ppmv at 0% O2 outlet (annual average).

Note A Total capital investment is estimated using cost data from a planned installation at an FCCU at another Marathon facility, scaled using the 0.6 power rule based upon stack flow rate.

Note B Electricity usage is estimated using engineering information from a planned installation at an FCCU at another Marathon facility, scaled directly based upon stack flow rate.

Note C EPA methodology for ammonia consumption was used according to the following formula: ((Uncontrolled NOx lb/hr) x (Removal efficiency) x SRF x MW-NH3)/MW-NOx/Csol, where SRF = Stoichiometric ratio factor = 1.05, MW-NH3 = 17.03, MW-NOx = 46.01, Csol = 19.5%. $900/ton based upon estimate of current market rates.

Note D EPA methodology for catalyst replacement was used according to the following formula: (Catalyst volume ft3) * (Catalyst cost $/ft3) * FWF, where Catalyst volume = 3,546 ft3 based on scaling from similar installation, cost = $227/ft3 per EPA default, FWF = 0.1452 based on 6 year catalyst life and 5.5% interest rate.

Note E EPA methodology: 0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost), where operator cost = 365 days/yr * $60/hr operator labor * 4 hr/da

Note F Control efficiency is based on average NOx concentration of 194 ppmv at 0% O2 during 2014 and controlled emissions of 20 ppmv at 0% O2 on an annual average

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 120 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 1,069,103,758 scf/Year

Enter the net plant heat input rate (NPHR) 8.20 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.27	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.015	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	55,577	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.5	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019			
CEPCI for 2019	592.1	Enter the CEPCI value for 2019	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia		
Electricity ($Cost_{elect}$)	0.0300	$/kWh		
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	120	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,160,264,901	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,069,103,758	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.921	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8072	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	94.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.14	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	125.68	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.18		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	6,381,721	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	19,760.72	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	322.95	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	6,648	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	7,645	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	87.4	feet
Reactor height =	$(R_{layer}$ + $R_{empty})$ x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	17	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	87	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,800	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	163.53	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$20,876,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$462,549	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,559,143	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,021,692	in 2019 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 =	$104,380	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$315,021	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$39,600	in 2019 dollars
Annual Catalyst Replacement Cost =		$3,548	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$462,549	in 2019 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) =	$3,881	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,555,262	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,559,143	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,021,692	per year in 2019 dollars
NOx Removed =	125.68	tons/year
Cost Effectiveness =	$16,086	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 96 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 891,901,862 scf/Year

Enter the net plant heat input rate (NPHR) 8 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.14	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	44,461	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	\$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	\$/kWh	
Catalyst cost ($CC_{replace}$)	227	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	\$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	96	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	928,211,921	scf/Year	
Actual Annual fuel consumption (Mactual) =		891,901,862	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.961	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8417	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	92.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	12.22	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	51.41	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.16		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	4,084,302	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	16,837.17	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	242.58	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	4,254	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	4,893	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	69.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	7	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	36	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,600	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	116.66	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$20,629,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$272,979	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,540,726	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,813,706	in 2019 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 =	$103,145	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$137,709	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$29,460	in 2019 dollars
Annual Catalyst Replacement Cost =		$2,665	in 2019 dollars
	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF		
Direct Annual Cost =		$272,979	in 2019 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) =	$3,866	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,536,861	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,540,726	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,813,706	per year in 2019 dollars
NOx Removed =	51.41	tons/year
Cost Effectiveness =	$35,276	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

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

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	128	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	906	Btu/scf
What is the estimated actual annual fuel consumption?	118,500,902	scf/Year
Enter the net plant heat input rate (NPHR)	8	MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	59,282	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	128	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,237,615,894	scf/Year	
Actual Annual fuel consumption (Mactual) =		118,500,902	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.096	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	839	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	89.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	11.27	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	4.73	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.12		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	7,260,981	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	23,336.64	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	311.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	7,564	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	8,698	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	93.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	51	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	262	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	34	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	11,300	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	Vendor estimate	1005.05	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$18,126,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$218,345	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,354,103	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,572,448	in 2019 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 =	$90,630	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$99,007	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$25,290	in 2019 dollars
Annual Catalyst Replacement Cost =		$3,418	in 2019 dollars
	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF		
Direct Annual Cost =		$218,345	in 2019 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) =	$3,716	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,350,387	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,354,103	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,572,448	per year in 2019 dollars
NOx Removed =	4.73	tons/year
Cost Effectiveness =	$332,721	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 67 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 412,446,843 scf/Year

Enter the net plant heat input rate (NPHR) 8 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365	days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10	lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu	Ammonia Slip (Slip) provided by vendor	10 ppm
Stoichiometric Ratio Factor (SRF)	1.05		Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
			Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

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

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours	Gas temperature at the SCR inlet (T)	650 °F
Estimated SCR equipment life	25.00	Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	31,030 ft^3/min-MMBtu/hour

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

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	67	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	647,814,570	scf/Year	
Actual Annual fuel consumption (Mactual) =		412,446,843	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.637	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5577	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	89.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.90	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	16.45	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.12		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,989,413	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	12,215.27	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	162.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,072	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,383	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	48.8	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	4	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	22	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	3	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,000	gallons (storage needed to store a 14 day reagent supply rounded to 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	111.34	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$16,534,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$157,993	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,235,403	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,393,396	in 2019 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 =	$82,670	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$54,904	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$18,630	in 2019 dollars
Annual Catalyst Replacement Cost =		$1,789	in 2019 dollars
	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF		
Direct Annual Cost =		$157,993	in 2019 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) =	$3,620	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,231,783	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,235,403	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,393,396	per year in 2019 dollars
NOx Removed =	16.45	tons/year
Cost Effectiveness =	$84,710	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	268	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	906	Btu/scf
What is the estimated actual annual fuel consumption?	1,467,372,583	scf/Year
Enter the net plant heat input rate (NPHR)	8	MMBtu/MW

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

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

Plant Elevation	23	Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.28	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	124,121	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	268	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,591,258,278	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,467,372,583	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.566	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4961	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	96.4	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	72.09	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	178.81	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.21		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	31,830,608	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	43,394.17	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	733.52	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	33,157	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	38,130	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	195.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	22	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	112	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	14	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	4,900	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	Vendor estimate	108.80	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$20,613,000	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$259,272	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,539,533	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,798,805	in 2019 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 =	$103,065	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$250,217	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$16,191	in 2019 dollars
Annual Fuel Savings (burners) =	(based on vendor estimates)	-$118,260	in 2019 dollars
Annual Catalyst Replacement Cost =		$8,059	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$259,272	in 2019 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) =	$3,865	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,535,669	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,539,533	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,798,805	per year in 2019 dollars
NOx Removed =	178.81	tons/year
Cost Effectiveness =	$10,060	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	268	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	906	Btu/scf
What is the estimated actual annual fuel consumption?	1,504,828,252	scf/Year
Enter the net plant heat input rate (NPHR)	8	MMBtu/MW

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

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

Plant Elevation: 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.26	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.010	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	124,121	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	268	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,591,258,278	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,504,828,252	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.581	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5087	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	96.2	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	67.27	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	171.10	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.20		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	31,830,608	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	43,749.38	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	727.57	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	33,157	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	38,130	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	195.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	21	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	109	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	14	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	4,800	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	106.09	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$20,613,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$259,206	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,539,533	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,798,740	in 2019 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 =	$103,065	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$250,217	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$16,191	in 2019 dollars
Annual Fuel Savings (burners) =	(based on vendor estimates)	-$118,260	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$7,994	in 2019 dollars
Direct Annual Cost =		$259,206	in 2019 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) =	$3,865	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,535,669	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,539,533	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,798,740	per year in 2019 dollars
NOx Removed =	171.10	tons/year
Cost Effectiveness =	$10,513	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 220 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 1,137,357,172 scf/Year

Enter the net plant heat input rate (NPHR) 8 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.04	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	101,890	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	220	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	2,127,152,318	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,137,357,172	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.535	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4684	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	75.4	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	6.74	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	15.77	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.94		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	21,449,674	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	46,726.60	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	459.05	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	22,343	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	25,695	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	160.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	11	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	56	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,500	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	75.79	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$13,999,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$203,596	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,046,393	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,249,990	in 2019 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 =	$69,995	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$117,908	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$10,650	in 2019 dollars
Annual Catalyst Replacement Cost =		$5,043	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$203,596	in 2019 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) =	$3,468	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,042,926	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,046,393	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,249,990	per year in 2019 dollars
NOx Removed =	15.77	tons/year
Cost Effectiveness =	$79,240	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 68 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 351,033,894 scf/Year

Enter the net plant heat input rate (NPHR) 8 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	31,493	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Densities of typical SCR reagents:

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	68	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	657,483,444	scf/Year	
Actual Annual fuel consumption (Mactual) =		351,033,894	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.534	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	4677	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	89.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.99	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	14.00	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.12		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,049,242	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	12,397.59	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	165.29	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,135	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,455	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	49.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	6	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	32	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,400	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	132.78	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$19,063,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$182,365	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,423,965	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,606,331	in 2019 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 =	$95,315	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$66,604	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$18,630	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$1,816	in 2019 dollars
Direct Annual Cost =		$182,365	in 2019 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) =	$3,772	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,420,194	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,423,965	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,606,331	per year in 2019 dollars
NOx Removed =	14.00	tons/year
Cost Effectiveness =	$114,739	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

What type of fuel does the unit burn? Natural Gas

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	391	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	906	Btu/scf
What is the estimated actual annual fuel consumption?	2,379,044,944	scf/Year
Enter the net plant heat input rate (NPHR)	8	MMBtu/MW

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

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

Plant Elevation: 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.14	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	181,087	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019		
CEPCI for 2019	592.1	Enter the CEPCI value for 2019 · 541.7 · 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia	
Electricity ($Cost_{elect}$)	0.0300	$/kWh	
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	391	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,780,529,801	scf/Year	
Actual Annual fuel consumption (Mactual) =		2,379,044,944	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.629	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5513	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	92.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	49.76	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	137.14	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.16		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	67,753,051	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	68,576.37	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	987.99	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	70,576	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	81,163	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	284.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	28	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	143	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	18	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,200	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	531.15	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$30,806,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$607,349	in 2019 dollars
Indirect Annual Costs (IDAC) =	$2,299,523	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,906,872	in 2019 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 =	$154,030	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$354,624	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$87,840	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$10,855	in 2019 dollars
Direct Annual Cost =		$607,349	in 2019 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) =	$4,476	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,295,047	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,299,523	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,906,872	per year in 2019 dollars
NOx Removed =	137.14	tons/year
Cost Effectiveness =	$21,196	per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

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

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

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 68 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 906 Btu/scf

What is the estimated actual annual fuel consumption? 385,137,680 scf/Year

Enter the net plant heat input rate (NPHR) 8 MMBtu/MW

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

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

Plant Elevation 23 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

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

Not applicable to units buring fuel oil or natural gas

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

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

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

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

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.10	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

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

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	10	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	52,560.00	hours
Estimated SCR equipment life	25.00	Years*

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

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	31,493	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19.50	percent
Density of reagent as stored (ρ_{stored})	58.39	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

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

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2,019			
CEPCI for 2019	592.1	Enter the CEPCI value for 2019	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	3.513	$/gallon for 19.5% ammonia		
Electricity ($Cost_{elect}$)	0.0300	$/kWh		
Catalyst cost ($CC_{replace}$)	227	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60	$/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4	hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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

Maintenance and Administrative Charges Cost Factors:

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

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Based on $900/ton market rate, converted to $3.51/gal using density and 7.48 gal/ft3
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	$30/MWh based on site-specific information.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

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

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	68	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	657,483,444	scf/Year	
Actual Annual fuel consumption (Mactual) =		385,137,680	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.586	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5131	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	89.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	5.99	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	15.36	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.12		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,049,242	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	12,397.59	/hour	
Residence Time	$1/V_{space}$	0.00	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.

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	0.1452	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})	165.29	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,135	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	1	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,455	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	49.5	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	41	feet

Reagent Data:

Type of reagent used: Ammonia

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

Density = 58.393 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	msol * Csol	6	lb/hour
Reagent Usage Rate (m_{sol}) =	Vendor estimate	31	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,400	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	Vendor estimate	137.19	kW

Cost Estimate

Total Capital Investment (TCI)

Total Capital Investment (TCI) =	$18,759,000	in 2019 dollars per vendor estimate

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$187,836	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,401,299	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,589,135	in 2019 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 =	$93,795	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$71,105	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$21,120	in 2019 dollars
Annual Catalyst Replacement Cost =		$1,816	in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$187,836	in 2019 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) =	$3,754	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,397,546	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,401,299	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,589,135	per year in 2019 dollars
NOx Removed =	15.36	tons/year
Cost Effectiveness =	$103,459	per ton of NOx removed in 2019 dollars

F-102 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$5,898,000	
Capital Cost and Installation		$5,698,000	Vendor estimate
Computational Fluid Dynamic Model		$200,000	Engineering estimate
Direct Operating Costs			
Electricity		$13,320	444 MWh/yr x $ 30.00 $/MW-hr per vendor estimate due to additional FD fans
Indirect Operating Costs			
Administration (2% total capital costs)		$117,960	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$58,980	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$58,980	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$493,541	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$729,461	
Total Annual Cost		**$742,781**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	134.18	85.6%	19.37	114.81	$6,470	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

F-301 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$4,762,000	
Capital Cost and Installation		$4,562,000	Vendor estimate
Computational Fluid Dynamic Model		$200,000	Engineering estimate
Direct Operating Costs			
Electricity		$0	N/A (no additional FD fans required)
Indirect Operating Costs			
Administration (2% total capital costs)		$91,240	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$45,620	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$45,620	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$398,481	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$580,961	
Total Annual Cost		**$580,961**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	5.51	61.0%	2.15	3.36	$172,807	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

F-652 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$4,506,000	
Capital Cost and Installation		$4,306,000	Vendor estimate
Computational Fluid Dynamic Model		$200,000	Engineering estimate
Direct Operating Costs			
Electricity		$0	N/A (no additional FD fans required)
Indirect Operating Costs			
Administration (2% total capital costs)		$90,120	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$45,060	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$45,060	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$377,059	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$557,299	
Total Annual Cost		**$557,299**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	18.55	59.7%	7.47	11.08	$50,296	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

F-751 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$8,972,000	Vendor estimate
Direct Operating Costs			
Electricity Savings		-$2,700	90 MWh/yr x $ 30.00 $/MW-hr per vendor estimate due to modifications
Fuel Savings		-$118,260	Vendor estimate due to increased efficiency
Total Direct Operating Costs		-$120,960	
Indirect Operating Costs			
Administration (2% total capital costs)		$179,440	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$89,720	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$89,720	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$750,771	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$1,109,651	
Total Annual Cost		**$988,691**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	187.00	60.9%	73.12	113.88	$8,682	Controlled emissions based on 0.11 lb/MMBtu per vendor estimate.

F-752 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$8,972,000	Vendor estimate
Direct Operating Costs			
Electricity Savings		-$2,700	90 MWh/yr x $ 30.00 $/MW-hr per vendor estimate due to modifications
Fuel Savings		-$118,260	Vendor estimate due to increased efficiency
Total Direct Operating Costs		-$120,960	
Indirect Operating Costs			
Administration (2% total capital costs)		$179,440	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$89,720	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$89,720	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$750,771	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$1,109,651	
Total Annual Cost		**$988,691**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	179.16	58.1%	74.99	104.18	$9,491	Controlled emissions based on 0.11 lb/MMBtu per vendor estimate.

F-6600 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$4,376,000	Vendor estimate
Direct Operating Costs			
Electricity		$0	N/A (no additional FD fans required)
Indirect Operating Costs			
Administration (2% total capital costs)		$87,520	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$43,760	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$43,760	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$366,181	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$541,221	
Total Annual Cost		**$541,221**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	15.55	59.1%	6.36	9.18	$58,926	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

F-6650-1-2-3 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$12,304,000	
Capital Cost and Installation		$12,104,000	Vendor estimate
Computational Fluid Dynamic Model		$200,000	Engineering estimate
Direct Operating Costs			
Electricity		$0	N/A (no additional FD fans required)
Indirect Operating Costs			
Administration (2% total capital costs)		$242,080	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$121,040	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$121,040	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$1,029,590	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$1,513,750	
Total Annual Cost		**$1,513,750**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	147.81	70.8%	43.11	104.70	$14,458	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

F-6601 - Ultra-Low NOx Burners (ULNB)

Control Equipment Costs

Category		**Value**	**Basis**
Total Capital Investment		$4,406,000	Vendor estimate
Direct Operating Costs			
Electricity		$0	N/A (no additional FD fans required)
Indirect Operating Costs			
Administration (2% total capital costs)		$88,120	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Property tax (1% total capital costs)		$44,060	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Insurance (1% total capital costs)		$44,060	EPA Air Pollution Control Cost Manual (Sec 2.6.5.8)
Capital Recovery	0.0837	$368,691	EPA Air Pollution Control Cost Manual (Sec 2.5.4.2)
5.50 % 20 year life			EPA default interest rate and estimated equipment life
Total Indirect Operating Costs		$544,931	
Total Annual Cost		**$544,931**	

Emission Control Cost Calculation

Pollutant	**Baseline Emissions (tpy)**	**Control Efficiency (%)**	**Controlled Emissions (tpy)**	**Emission Reduction (tpy)**	**Control Costs ($/ton)**	**Basis**
Nitrous Oxides (NOx)	17.11	59.2%	6.98	10.13	$53,802	Controlled emissions based on 0.040 lb/MMBtu per vendor estimate.

U.S. OIL & REFINING CO.

April 29, 2020

CERTIFIED MAIL
7019 0700 0001 7342 9271

Mr. Chris Hanlon-Meyer
Science and Engineering Section Manager -- Air Quality Program
Washington Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

Subject: U.S. Oil & Refining Co. Regional Haze 4-Factor Analysis Report

Reference: (a) Letter Dated November 27, 2019 from Chris Hanlon-Meyer to Ty Gaub Requesting the Completion of a Regional Haze 4-Factor Analysis

(b) Letter Dated April 10, 2020 from Chris Hanlon-Meyer to Bob Poole Stating that Ecology will accept Regional Haze 4-Factor Analysis data from WA refineries no later than April 30, 2020

Dear Mr. Hanlon-Meyer:

Per references (a) and (b) U.S. Oil & Refining Co. submits the enclosed Regional Haze 4-Factor Analysis report in response to the Department of Ecology's information request dated November 27, 2019.

The document provides a detailed analysis of various control technologies for two boilers and one process heater with fired duty capacities that exceed 40 MMBtu/hr. (Ecology's November 27, 2019 letter also requested that refineries evaluate fluidized catalytic cracking unit boilers exceeding 40 MMBtu/hr; U.S. Oil does not have a source of this type.) This evaluation used the methodology specified by the U.S. Environmental Protection Agency for conducting a regional haze 4-Factor analysis. The analysis concludes that additional control technologies – beyond the refinery's existing approach of burner technology and good combustion practices – are either technically infeasible or not cost-effective. We believe this finding is consistent with U.S. Oil's very small estimated impact on visibility impairment in Class I airsheds, which is markedly lower than other industrial facilities being evaluated in the regional haze planning process.

Please contact me at 253-383-1651 or tgaub@parpacific.com if questions arise on this analysis.

Sincerely,

U.S. OIL & REFINING CO.

Ty J. Gaub
Environmental Manager

Enclosure

Cc: AJT, RLG, JBG, DKN

F:/gpr/eh&s/documents/rlg/RLG20007.doc

3001 Marshall Ave., Tacoma WA 98421-0116 • e-mail: tgaub@parpacific.com
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REGIONAL HAZE FOUR-FACTOR ANALYSIS

U.S. Oil & Refining Co. > Tacoma, WA Refinery

Prepared By:

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April 2020

Project 204801.0016

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1. EXECUTIVE SUMMARY

On November 27, 2019, Washington Department of Ecology (Ecology) sent a letter to U.S. Oil & Refining Co. (U.S. Oil) requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" U.S. Oil's Tacoma refinery (the refinery).[1] U.S. Oil understands that the information provided in a four-factor review of control options will be used by Ecology and the EPA in their evaluation of reasonable progress goals under the Regional Haze program for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, U.S. Oil understands that Ecology will only move forward with requiring emission reductions from the refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost-effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

While U.S. Oil was incorporated into the regional haze efforts as a refinery in the state, it is worth noting that from an emissions standpoint, the Tacoma refinery had a Q/d ratio of less than one-third of the threshold used by the state as a screening value to determine which facilities should be evaluated. With a total combined emissions of visibility-impairing pollutants of 149.17 tons, the Q/d ratio (a ratio of total emissions over the distance to the nearest Class I area) was 3.21. A threshold of 10 was used to determine which facilities contributed to visibility impairment at Class I areas enough to warrant a four-factor analysis. U.S. Oil's contributions to visibility impairment at Class I areas in the region is substantially lower than the majority of other facilities being evaluated.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus the control cost development on low-NO_X burners (LNB) and selective catalytic reduction (SCR) for NO_X emissions. Therefore, a complete four-factor analysis is provided for SCR and LNBs. For completeness, a qualitative discussion of each of the remaining pollutants is included in this analysis.

U.S. Oil does not exclude SCR from consideration on the basis of technical infeasibility for the units evaluated in this report. Unit-specific vendor evaluations would be required to confirm technical feasibility; however, these are unnecessary given the cost of this control option. SCR cost calculations are developed using the EPA Control Cost Manual. Where applicable, site- and unit-specific values are used for process variables or costs. Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery.

For the purposes of this analysis, cost calculations are developed for LNBs. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including boiler/heater geometry, burner footprint, reusability of the windbox, variability of combustion air flow, heat flux distribution and heat density, tube metal temperature distribution, and overall flow pattern and temperature of the flue gas are potentially engineering constraints. Information received from Callidus and John Zink, burner manufacturers, indicates that ultra low-NO_X burners are not technically feasible at the firing rates indicated in Table 3-1, and that the feasibility of current-generation low-NO_X burners that are capable of achieving lowering NO_X emission levels than currently-installed low-NO_X burners is inconclusive. Though they may not be technically feasible, U.S. Oil includes a cost-effectiveness

[1] Letter from Chris Hanlon-Meyer of Ecology to Ty Gaub of U.S. Oil dated November 27, 2019.

analysis for LNB retrofits in this report. LNB cost-effectiveness metrics are lower than those of SCR. U.S. Oil concludes that the existing emissions reduction method of good combustion practice is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the regional haze program to maintain Washington's reasonable progress toward visibility goals.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

> (A) *consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
>
> (B) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On November 27, 2019, Ecology sent a letter to US Oil requesting that they provide "information for a 4-Factor analysis for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at" U.S. Oil & Refining Co.'s Tacoma, WA refinery.[2] US Oil understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Washington. The purpose of this report is to provide information to Ecology regarding potential PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 emission reduction options for the US Oil refinery. Based on the Regional Haze Rule, associated EPA guidance, and Ecology's request, US Oil understands that Ecology will only move forward with requiring emission reductions from the US Oil Refinery if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to Ecology. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

---

[2] Letter from Ecology to P66 dated November 27, 2019.

In the November 27th letter, Ecology also requested that U.S. Oil "include all information regarding activities that have the potential to reduce the cost of compliance." As a standard practice, the refinery evaluates projects undertaken at the refinery for the potential to reduce costs through energy efficient design and timing of maintenance.

In email correspondence with Bob Poole of the Washington State Petroleum Association (WSPA), Ecology's Chris Hanlon-Meyer provided further clarification on the needed analysis from each refinery, specifying that analyses should focus on control cost development for low-NO_X burners and selective catalytic reduction (SCR). For NO_X emissions, a complete four-factor analysis is provided for SCR and low-NO_X burners. For completeness, a qualitative discussion of each of the remaining pollutants is also included in this analysis.

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the units

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[3] for conducting a review of Best Available Retrofit Technology (BART) for a unit. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for PM_{10}, SO_2, NO_X, H_2SO_4, and NH_3 can be found in Sections 5-9 of this report, respectively. Section 4 of this report includes information on the US Oil's existing/baseline emissions for the emission units relevant to Ecology's regional haze efforts.

[3] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

3. SOURCE DESCRIPTION

US Oil is located on 136 acres in the deep-water Port of Tacoma, Washington. This includes 11.5 waterfront acres with 1,350 feet of waterfront on the Blair Waterway which provides direct access by ocean-going barges and tankers. The refinery and marine terminal are connected by four pipelines varying in size from 8 to 24 inches. The refinery has direct rail access and is close to both a major interstate highway system and the Seattle-Tacoma International Airport.

Figure 3-1. Aerial View of the U.S. Oil Tacoma Refinery

While U.S. Oil was incorporated into the regional haze efforts as a refinery in the state, it is worth noting that from an emissions standpoint, the Tacoma refinery had a Q/d ratio of less than one third of the threshold used by the state as a screening value to determine which facilities should be evaluated. With a total combined emissions of visibility-impairing pollutants of 149.17 tons, the Q/d ratio (a ratio of total emissions over the distance to the nearest Class I area) was 3.21. A threshold of 10 was used to determine which facilities contributed to visibility impairment at Class I areas enough to warrant a four-factor analysis. U.S. Oil's contributions to visibility impairment at Class I areas in the region is substantially lower than the majority of other facilities being evaluated.

Per the four-factor analysis request from Ecology, the following units are considered applicable for completion of a four factor analysis if they have not been retrofitted since 2005:

- Fluid Catalytic Cracking Units (FCCUs)
- Boilers greater than 40 MMBtu/hr
- Heaters greater than 40 MMBtu/hr

Taking into account both these source types and the timeline of projects at the US Oil refinery, the following units are applicable for this four-factor analysis:

Table 3-1. Summary of Applicable Emission Units

Emission Unit	Heat Input Capacity (MMBtu/hr)
Package Steam Boiler B-4	99.0
Package Steam Boiler B-5	80.0
Process Heater H-11	105.9

A detailed analysis of the control options available for each of these three units is provided for each of the pollutants applicable to Ecology's request for a four-factor analysis.

4. BASELINE EMISSIONS

In order to establish a representative baseline against which any potential emission reduction measures could be assessed, US Oil is using projected actual emissions for the heater and boilers. US Oil is implementing changes during the refinery's upcoming turnaround in early 2021 that will add significant heat recovery, thereby reducing the fired duties of these sources. These improvements will lower NO_X emissions without the need for new emission controls, and provide a realistic baseline for evaluating the cost-effectiveness of any emission controls installed after 2021. The projected emissions represent the anticipated future actual emissions based on existing equipment and anticipated firing rates, reflecting improvements in heating efficiency from these units. Emissions for each pollutant and applicable unit for regional haze are provided in Table 4-1 below.

Table 4-1. Summary of Baseline Emissions

Emission Unit	Total Annual Emissions (tons)				
	NO_X	SO_2	PM_{10}	NH_3	H_2SO_4
B-4	24.96	0.60	1.18	--	7.35E-04
B-5	10.39	0.29	0.56	--	3.49E-04
H-11	31.56	1.16	2.30	--	1.43E-03

5. NO_X FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

In order to minimize NO_X emissions from a combustion unit, controls can take the form of either combustion or post-combustion methods. Low-NO_X burners (LNB) work to limit NO_X formation during combustion, using various methods to reduce peak flame temperature and increase flame length. Selective catalytic reduction (SCR) addresses NO_X emissions post-combustion, using catalyst and reagent to convert NO_X to elemental nitrogen before emissions leave the stack. Both controls are explained in more detail below. Good combustion practices are also described, as they represent the current emissions reduction method for several of the burners and heaters at the refinery.

5.1.1. Combustion Controls

5.1.1.1. Low-NO_X Burners (LNB)

LNB are some of the most widely used NO_X control devices for refinery process heaters today. Different burner manufactures use different burner designs to achieve low NO_X emissions, but all designs essentially implement two fundamental tactics - low excess air and staged combustion. Low excess air decreases the total amount of nitrogen present at the burner, thereby decreasing the resulting thermal NO_X formation. Staged combustion burns fuel in two or more steps. The primary combustion zone is fuel-rich, and the secondary zones are fuel-lean. Using these tactics, LNBs inhibit thermal NO_X formation by controlling the flame temperature and the fuel/air mixture within the flame burner zone.

5.1.1.2. Good Combustion Practices

NO_X emissions can be controlled by maintaining various operational combustion parameters. These operational methods can include staged fuel combustion, staged air combustion, and low excess air combustion. The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. This is an appropriate control option for small heaters in which emissions are considered to be de minimis. Good combustion practices are the selected control option for several emission units found in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, which provides control units required as part of programs more stringent in requirement than the regional haze program, including consent decrees and the Prevention of Significant Deterioration Best Available Control Technology (PSD BACT) program. The detailed RBLC database search results are included in Appendix A of this report.

5.1.2. Post Combustion Controls

5.1.2.1. Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[4] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1. Combustion Controls

5.2.1.1. Low-NO_X Burners

When the current burners were installed on both of the boilers and the heater, the burners were designed as LNBs, as documented in the permit history for these units. For the purpose of this four-factor analysis, U.S. Oil is including current-generation LNBs as a technically feasible emissions reduction option. This context is important, as the incremental improvements to NO_X emissions from the burner retrofits will be less substantial than the retrofitting of older burners that were not considered "low-NO_X" at the time of installation.

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[4] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

Burner design, operating conditions, and surrounding equipment can heavily influence technical feasibility for burner retrofits.

Per correspondence with a burner vendor (John Zink Hamworthy Combustion), an engineering evaluation including a computational fluid dynamics simulation would be required in order to determine whether implementation of current-generation low-NO_X burners is technically feasible. Possible technical concerns that may affect technical feasibility and/or retrofit costs include boiler/heater geometry, reusability of the windbox, variability of combustion air flow, heat flux distribution, tube metal temperature distribution, and overall flow pattern and temperature of the products of combustion. Additionally, per discussions with John Zink, their proposed low-NO_X burner for Heater H-11 would not fit within the existing floor cutout, which would require substantial retrofitting. The costs presented in this four-factor analysis are predicated on the unproven assumption that LNB are technically feasible, and are based on preliminary estimates from vendors. It is important to note that actual costs could be substantially higher for a given unit if additional boiler or heater changes are required. These estimates serve as initial evaluations based on burner parameters, but additional evaluation is required to obtain more detailed assessments of cost and technical feasibility. Though ultra low-NO_X burners (ULNB) were not included in the focused scope of Ecology's request for this analysis, US Oil did contact John Zink and Callidus regarding the potential for an ultra low-NO_X burner (ULNB) retrofit. Both vendors indicated that ULNB would not be technically feasible for the H-11 heater, citing concerns with heat density and fuel pressure that render the retrofit technically infeasible.

5.2.1.2. Good Combustion Practices

Good combustion practices are currently employed for the boilers and heater and are therefore considered technically feasible. Good combustion practices are considered the baseline emissions reduction method for this analysis, and all emissions reductions estimates use this control as a baseline.

5.2.2. Post Combustion Controls

5.2.2.1. Selective Catalytic Reduction

SCR is a widely accepted emissions control technology for heaters and burners in the industry. While specific circumstances such as exhaust temperature can result in SCR implementation challenges or even infeasibility for a given unit, the technology more broadly is considered technically feasible.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

The effectiveness of LNBs vary from unit to unit – control cost calculations are calculated on the basis of an anticipated NO_X emission factor on a lb NO_X per million Btu's basis (lb/MMBtu). The efficiencies are summarized in Table 5-1, below. Detailed cost calculations are provided in Appendix B of this report.

Table 5-1. Summary of Emissions Reduction Effectiveness

Emissions Reduction Method	Control Efficiency
Selective Catalytic Reduction (SCR) [1]	90%
Low-NO_X Burners (LNB) [2]	62-65%
Good Combustion Practices	Baseline

[1] SCR control efficiency, for the purposes of the cost calculations and four-factor analysis, is assumed to be 90% based on data provided in the EPA Control Technology Fact Sheet for SCR. https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

The use of this control efficiency is a conservative approximation, and testing would be required on a unit-by-unit basis to determine what level of control is attainable, particularly given concerns of ammonia slip that can result in impacts counter to the goals of the regional haze program.

[2] LNB control efficiency is calculated by comparing baseline emission levels to an anticipated controlled NO_X emission rate of 0.06 lb NO_X/MMBtu of heat input. This controlled NO_X emission rate is provided in preliminary estimates obtained from John Zink.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

5.4.1.1. Selective Catalytic Reduction Cost Calculations

SCR cost calculations are developed using the EPA Control Cost Manual. Where applicable, site- or location-specific values are used for the various inputs to the control cost methodology. Cost estimations are preliminary, and additional unit-specific engineering and analysis will be necessary to determine the feasibility of a retrofit and is expected to result in substantially higher costs.

Costs are converted to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). A retrofit factor of 1.5 applied to the capital cost estimates, consistent with the EPA Control Cost Manual. This retrofit factor accounts for the additional engineering involved with changes to the heater or boiler, such as altering fan capacity, changes to furnace geometry, and adding systems to the flue gas flow to allow for better control and stabilization of stream conditions like temperature. Additionally, current boiler stack arrangement and the lack of adjacent space for an SCR footprint will necessitate substantial ducting to route flue gas to an SCR system.

SCR cost calculations are summarized in Table 5-2. Detailed cost calculations are included in Appendix B.

Table 5-2. Summary of SCR Cost Calculations

Unit ID	Annual Cost ($/year)	Emissions Reduced (tons/year)	Cost Effectiveness ($/ton)
B-4	$490,838	22.47	$21,847
B-5	$417,032	9.35	$44,584
H-11	$522,175	28.40	$18,387

[1] SCR cost estimations are preliminary. Additional engineering and design evaluation is required to determine cost and feasibility for each individual emission unit, which is expected to result in additional costs for implementation of the retrofits.

5.4.1.2. Low-NO_X Burner Cost Calculations

LNB cost calculations are developed based on preliminary estimates obtained from John Zink. Complete, equipment-specific evaluations have not been conducted at this time; therefore, costs are preliminary. Additional evaluations will be required and are expected to result in higher costs. EPA's Control Cost Manual is used to provide estimates of overhead, contingencies, and other associated engineering costs involved with retrofitting the burners.[5] LNB cost calculations are summarized in Table 5-3, and detailed cost calculations are included in Appendix B.

Table 5-3. Summary of LNB Cost Calculations

Unit ID	Annual Cost ($/year) [1]	Emissions Reduced (tons/year)	Cost Effectiveness ($/ton)
B-4	$67,632	11.03	$6,131
B-5	$61,400	3.77	$16,282
H-11	$99,337	9.02	$11,018

[1] LNB capital and installation costs are based on preliminary vendor estimates. Additional engineering and design evaluation is required to determine cost and feasibility for each individual emission unit, which is expected to result in additional costs for implementation of the retrofits.

5.4.2. Timing for Compliance

U.S. Oil believes that the equipment currently in place at the refinery complies with any requirements for attaining reasonable progress under the regional haze program, and that no additional controls are needed. Any changes to heaters or boilers at the refinery may need to be incorporated into the schedule of a future refinery turnaround or annual boiler shutdown. Refinery turnarounds are infrequent and complex undertakings that require several years of advance planning. However, if Ecology determines that one of the NO_X reduction options analyzed in this report is necessary to achieve reasonable progress, it may not be possible to incorporate emission control upgrades into a refinery turnaround until at least 2026 and possibly later.

5.4.3. Energy Impacts and Non-Air Quality Impacts

The cost of energy required to operate SCR has been included in the cost analyses found in Appendix B. To operate the SCR, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Reheating the flue gas, as necessary, for SCR application would also require substantial natural gas usage with an associated increase in direct emissions (including greenhouse gas emissions). The use of NO_X reduction methods that incorporate ammonia injection like SCR leads to increased health risks to the local community from ammonia slip emissions. Additionally, there is an added compliance burden under EPA's Risk Management Program, as well as safety concerns associated with the transport and storage of ammonia, including potential ammonia releases that can have serious adverse health impacts.

5.4.4. Remaining Useful Life

The remaining useful life for all units evaluated in this analysis is at least 20 years, and thus is not considered to have an impact on the feasibility or applicability of either emissions reduction option being considered.

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[5] Indirect installation costs developed using methods consistent with the "OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

5.5. NO_X CONCLUSION

Cost calculations indicate that SCR is not a cost-effective control for NO_X emissions at the refinery. Where applicable, site- and unit-specific values are used for process variables or costs. SCR cost calculations are developed using the EPA Control Cost Manual. U.S. Oil does not exclude SCR from consideration on the basis of technical infeasibility for the units evaluated in this report, but unit-specific vendor evaluations will be required to confirm feasibility.

For the purposes of this analysis, cost calculations are developed for current-generation LNBs. Given the unit-specific factors that can influence the feasibility of LNB retrofits, including boiler/heater geometry, burner footprint, reusability of the windbox, variability of combustion air flow, heat flux distribution and heat density, tube metal temperature distribution, and overall flow pattern and temperature of the flue gas are potentially engineering constraints. While U.S. Oil has not ruled out LNB retrofits on the basis of technical feasibility in this analysis, a more thorough, unit-specific evaluation by vendors will be required to determine if the installation of current-generation low-NO_X is technically feasible. Based on the costs presented in this report, LNB is not a cost-effective technology to implement on these units. U.S. Oil concludes that the existing emissions reduction method of good combustion practice with the existing LNBs is consistent with recent determinations for units of similar size under more stringent regulatory programs (such as the Prevention of Significant Deterioration Best Available Control Technology program), and thus is consistent with the needs of the Regional Haze Program to maintain Washington's reasonable progress toward visibility goals.

6. PM_{10}, SO_2, NH_3, AND H_2SO_4 EVALUATION

Per Ecology's direction, the only emissions controls being evaluated for a complete four-factor analysis are SCR and low-NO_X burners for NO_X emissions control. The following section is provided for completeness to address the initial four-factor analysis request for PM_{10}, SO_2, NH_3, and H_2SO_4. This section of the report provides a qualitative assessment of the four additional pollutants other than NO_X, with conclusions consistent with Ecology's direction that a detailed analysis of these pollutants is not necessary for these pollutants.

The baseline emission rates for PM_{10}, SO_2, NH_3, and H_2SO_4 are summarized in Table 4-1The basis of the emission rates is provided in Section 4 of this report.

The U.S. EPA's RBLC database and historic BACT reports for the facility were searched to identify possible control technologies that could be used to reduce PM_{10}, SO_2, NH_3, and H_2SO_4 emissions from applicable units for regional haze at the Tacoma refinery. To ensure all potentially relevant control methodologies are considered, the search was conducted both for combustion units less than 100 MMBtu/hr of heat input and combustion units with a heat input between 100 and 250 MMBtu/hr.

In the case of PM_{10} and H_2SO_4, the RBLC results included only good combustion practices for emissions controls. This is consistent with current practices at the Tacoma refinery, and US Oil concludes that no additional controls or emission reduction measures are necessary for the Tacoma refinery.

For SO_2 entries in the RBLC database, the control technologies likewise included combustion practices, with the use of low-sulfur fuels for combustion also included. Continuous Emission Monitoring System (CEMS) are currently used to monitor inlet fuel sulfur content to ensure compliance with the low-sulfur fuel requirements of NSPS Subpart J or BACT permit limits for units sharing the same fuel gas system. Good combustion practices and the use of low-sulfur fuels are consistent with current practices at the Tacoma refinery, and no additional emissions reductions options are required to maintain practices consistent with those found in the RBLC database.

Finally, for NH_3 there are currently no appreciable NH_3 emissions from the equipment currently evaluated for the four-factor analysis. Should emissions controls be installed that involve the use of ammonia, then there is the potential for ammonia slip to result. No additional emission reduction measures are appropriate at this time.

No additional control measures were identified as appropriate for the process heaters and boilers applicable to regional haze at this facility. Therefore, no additional controls or emission reduction options are evaluated for PM_{10}, SO_2, NH_3, and H_2SO_4 in this analysis.

APPENDIX A : RBLC SEARCH RESULTS

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Ammonia (NH3)	ammonia slip will be less than 10 ppmv	OTHER CASE-BY-CASE
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE).	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx anual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Nitrogen Oxides (NOx)	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Nitrogen Oxides (NOx)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Nitrogen Oxides (NOx)	LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Nitrogen Oxides (NOx)	Good combustion practices	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Nitrogen Oxides (NOx)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Nitrogen Oxides (NOx)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Nitrogen Oxides (NOx)	Low-NOx burners	N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Nitrogen Oxides (NOx)	Ultra low NOx burner	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Nitrogen Oxides (NOx)	Low-NOx gas burner	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Nitrogen Oxides (NOx)	Low-NOX burners, good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Nitrogen Oxides (NOx)	Low NOX burners, use of natural gas and good combustion practices	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Nitrogen Oxides (NOx)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	LAER
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Nitrogen Oxides (NOx)	ultra-low NOx burners	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	MSS-Heaters		0		Heaters are used to abate MSS emissions directed to them. Nox emission factor from the heaters will be 0.025 lb/MMBtu, during 8 hours at startup and 4 hours of shutdown. CO emissions will be limited to 100 pppmv from heaters during 8 hours at startup and 4 hours of shutdown.	Nitrogen Oxides (NOx)	NOx emission factor will be 0.025 lb/MMbtu, during 8 hours at startup and 4 hours of shutdown NOx annual emission factor from heaters when they are abating MSS emissions will be 0.006 lb/MMBtu, annually	LAER
GALENA PARK TERMINAL	KM LIQUIDS TERMINALS LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	6/12/2013	5/9/2016	Tank Terminal	Heaters	Natural gas	129	MMBTU/H	Maximum firing rate of 129 MMBtu/hr and heaters will be equipped with ultra low NOx burners and SCR. Natural gas fired at the heaters are sampled for sulfur every 6 months . Heaters will be sampled for NOx, CO, PM.	Nitrogen Oxides (NOx)	low-NOx burners and SCR	LAER

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	4/10/2015	5/16/2016	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		(2) 129 Million British Thermal Units per hour (MMBtu/hr) direct-fired process heaters and (2) 106 MMBtu/hr thermal fluid heaters (one pair for each train)	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	BACT-PSD
LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	11/3/2016	11/16/2017	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Thermal Fluid (â€œhot oilâ€) Heater, throughput based on higher heating value basis	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Nitrogen Oxides (NOx)	ultra low-NOâ€ž burners	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Nitrogen Oxides (NOx)	Ultra Low NOx burners	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur /carbon fuel and good combustion practices	N/A
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, filterable (FPM)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, filterable (FPM)	Operate and maintain in accordance with manufacturer's design	BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, filterable (FPM)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, filterable (FPM)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, filterable (FPM)	Good combustion practices	BACT-PSD
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, filterable (FPM)		N/A
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	12/20/2010	1/8/2014	Power plant that contains four combustion turbines, four duct burners, a black start generator, and an auxiliary heater.	Fuel Combustion	Diesel	12.5	MMBTU/H	Auxiliary Heater	Particulate matter, total < 10 Âµ (TPM10)	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 10 Âµ (TPM10)	Limited Use (200 hr/yr)	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 10 Âµ (TPM10)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 10 Âµ (TPM10)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #1	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
AGP SOY	AG PROCESSING INC., A COOPERATIVE	NE	NEBRASKA DEPT. OF ENVIRONMENTAL QUALITY	3/25/2015	8/18/2015	Soybean Processing Facility	Boiler #2	natural gas	200	MMBTU/H	The boiler is capable of combusting natural gas and Fuel Oil	Particulate matter, total < 10 Âµ (TPM10)		BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Particulate matter, total < 10 Âµ (TPM10)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Particulate matter, total < 10 Âµ (TPM10)		N/A
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 10 Âµ (TPM10)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 10 Âµ (TPM10)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practice	LAER
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Particulate matter, total < 10 Âµ (TPM10)	Low sulfur/carbon fuel and good combustion practices	N/A

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	AMMONIA START-UP HEATER (102-B)	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	LOUISIANA DEPARTMENT OF ENV QUALITY	3/27/2013	5/4/2016	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES: PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING THE PROPER AIR-TO-FUEL RATIO, RESIDENCE TIME, AND COMBUSTION ZONE TEMPERATURE.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Limited Use (200 hr/yr)	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Particulate matter, total < 2.5 Âµ (TPM2.5)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	ILLINOIS EPA, BUREAU OF AIR	11/1/2018	2/19/2019	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Gas-Fired Space Heaters	Natural Gas	25	mmBtu/hr	Throughput addresses all space heaters	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	INDIANA DEPT OF ENV MGMT, OFC OF AIR	9/25/2013	5/4/2016	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EAC	FUEL INPUT TO ALL FOUR BOILERS SHALL NOT EXCEED 2,802 MMCF/YEAR	Particulate matter, total < 2.5 Âµ (TPM2.5)	PROPER DESIGN AND GOOD COMBUSTION	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	11/17/2017	3/8/2018	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	A natural gas fired auxiliary boiler, rated at 182 MMBTU/H to provide auxiliary steam when the plant is off-line, used to maintain warm drums on the HRSG and maintain the steam turbine generator seals.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Combustion control	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Startup boiler (B001)	Natural gas	15.17	MMBTU/H	Startup boiler, natural gas fired with maximum heat input of 15.17 MMBtu/hr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Process gas heater (P001)	Natural gas	218.9	MMBTU/H	Process gas preheater, natural gas, indirect fired with maximum heat input of 218.9 MMBtu/hr, emissions are vented to a stack.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	2/6/2019	6/19/2019	Merchant Pig Iron Production	Ladle Preheaters (P002, P003 and P004)	Natural gas	15	MMBTU/H	Three identical Ladle dryers / preheaters, natural gas fired with maximum heat input of 15.00 MMBtu/hr, emissions are vented to the EAF baghouse. Throughputs and limits are for one preheater, except as noted.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of natural gas	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	LAER
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Particulate matter, total < 2.5 Âµ (TPM2.5)		BACT-PSD
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf on a 12 mo rolling av.	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Three (3) New Natural Gas-Fired 243 MMBtu/hr Package Boilers	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Five (5) Natural Gas-Fired 50 MMBtu/hr Waste Heat Boilers. Installed in 1986.	Particulate matter, total (TPM)		BACT-PSD
KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	ALASKA DEPT OF ENVIRONMENTAL CONS	1/6/2015	2/19/2016	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American Industrial Classification code 325311. The facility will produce ammonia and urea for bulk sale. There are two ammonia and two urea plants at Agriumâ€™s KNO facility. This permit authorizes the restart of one ammonia and one urea plant (plants 4 and 5). The ammonia plant converts natural gas with added steam and air to produce ammonia (NH3) and carbon dioxide (CO2). Feedstocks for the urea plant include CO2 and NH3. The utility plant generates the power and steam needed to operate the ammonia and urea plants. Final products are loaded at the Product Loading Wharf for shipment.	Startup Heater	Natural Gas	101	MMBTU/H	Natural Gas-Fired 101 MMBtu/hr Startup Heater. Installed in 1976.	Particulate matter, total (TPM)	Limited Use (200 hr/yr)	BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Boiler, Nat Gas Fired	NATURAL GAS	261	MMBTU/H	261 MMBTU/H natrual gas-fired boiler, equipped with low-NOx burners, SCR, and CO catalytic oxidation	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Regeneration Heater, methanol to gasoline	NATURAL GAS	13	MMBTU/H	13 MMBTU/H methanol-to-gasoline regeneration heater, equipped with low-NOx burner	Particulate matter, total (TPM)		BACT-PSD
EMBERCLEAR GTL MS	EMBERCLEAR GTL MS LLC	MS	MISSISSIPPI DEPT OF ENVIRONMENTAL QUALITY	5/8/2014	11/7/2016	Proposed gas-to-liquids (GTL) plant, processing pipeline natural gas into gasoline and LPG through a series of reforming processes, including a Steam Methane Reformer (SMR) and an Auto Thermal Reformer (ATR)	Reactor Heater, 5	NATURAL GAS	12	MMBTU/H	Five 12 MMBTU/H reactor heaters, equipped with low-NOx burners	Particulate matter, total (TPM)		BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Particulate matter, total (TPM)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Particulate matter, total (TPM)	Gas combustion control	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Particulate matter, total (TPM)	Combustion control	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Particulate matter, total (TPM)	Good combustion practices	BACT-PSD
JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	TENN.DEPT. OF ENVIRONMENT & CONSERVATION, DIV OF AIR POLLUTION CONTROL	4/19/2016	5/11/2018	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate.	Particulate matter, total (TPM)	Good combustion design and practices	BACT-PSD
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	ARKANSAS DEPT OF ENVIRONMENTAL QUALITY	9/18/2013	12/13/2016	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	SMALL HEATERS AND DRYERS SN-05 THROUGH 19	NATURAL GAS	0		RH VESSEL PREHEATER STATION, VESSEL TOP PART DRYER, RH VESSEL NOZZLE DRYER RH DEGASSER BURNER/LANCE LADLE PREHEATERS LADLE DRYOUT STATION VERTICAL LADLE HOLDING STATION TUNDISH PREHEATERS #1 THROUGH #4	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	One natural gas-fired auxiliary boiler rated at 182 MMBTU/H fuel heat input.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
INDECK NILES, LLC	INDECK NILES, LLC	MI	MICHIGAN DEPT OF ENVIRONMENTAL QUALITY	1/4/2017	3/8/2018	Natural gas combined cycle power plant.	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	Natural gas	27	MMBTU/H	Two natural gas fired dew point heaters for warming the natural gas fuel (EUFUELHTR1 & EUFUELHTR2 in flexible group FGFUELHTR). The total combined heat input during operation shall not exceed 27 MMBTU/H (each) as well. The CO2e limit is for both units combined; however the other limits are per unit.	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	BACT-PSD
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		The natural gas throughput is unknown; the limits are based on the potential of 8760 hours of operation. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	12/14/2010	10/13/2011	Canned food maufacturing facility.	Bolier (3)	Number 2 fuel oi	3246593	GAL/YR	Number #2 fuel oil is backup. This throughput restriction on the 3 boilers together keeps the permit PSD for only CO. Boilers used for cogeneration of heat to facility.	Sulfur Dioxide (SO2)		OTHER CASE-BY-CASE
KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	1/15/2013	5/4/2016	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0.05 % sulfur.	N/A
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	BACT-PSD
FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	TX	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ)	7/16/2014	5/9/2016	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNGâ€™s existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Developmentâ€™s existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNGâ€™s existing 42-inch gas pipeline.	Heating Medium Heaters	natural gas	130	MMBTU/H	There are (5) heaters each at 130 MMBtu/hr which operate when the turbine exhaust is not providing enough heat for the amine regenrating heating oil system	Sulfur Dioxide (SO2)		BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfur Dioxide (SO2)	Low sulfur fuel	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfur Dioxide (SO2)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	OTHER CASE-BY-CASE
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD

Facility Name	Corporate or Company Name	Facility State	Agency Name	Permit Issuance Date	Date Determination Last Updated	Facility Description	Process Name	Primary Fuel	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Case-by-Case Basis
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD
NTE OHIO, LLC		OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	11/5/2014	4/1/2019	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	A natural gas-fired auxiliary boiler, rated at 150 MMBtu/hr will be used primarily to provide high-temperature steam when the CTG is offline in order to accommodate more rapid startups after extended shutdowns and potentially to provide fuel gas heating.	Sulfuric Acid (mist, vapors, etc)	Exclusive Natural Gas	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	185.0 MMBtu/hr natural gas-fired boiler with low-NOx burners and flue gas recirculation (FGR)	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	OHIO ENVIRONMENTAL PROTECTION AGENCY	10/23/2017	6/19/2019	1,650 MW combined cycle combustion turbine electrical generating facility	Fuel Gas Heaters (2 identical, P007 and P008)	Natural gas	15	MMBTU/H	Two identical Fuel Gas Heaters; 15.0 MMBtu/hr natural gas-fired fuel gas heater with low-NOx burners. The natural gas heaters will heat a water bath.	Sulfuric Acid (mist, vapors, etc)	Pipeline natural gas fuel	BACT-PSD
TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY	2/12/2016	12/21/2018	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Total fuel usage of the auxiliary boiler shall not exceed 1052 MMsch/yr on a 12-month rolling basis	Sulfuric Acid (mist, vapors, etc)	Good combustion practices	BACT-PSD
GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	6/17/2016	6/19/2019	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	The auxiliary boiler will provide steam to the steam turbine at startup and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the combustion turbines or steam turbine. The boiler is proposed to operate 8760 hrs/yr but will be limited by an annual fuel throughput based on a capacity factor of 10%.	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas	N/A
C4GT, LLC	NOVI ENERGY	VA	VIRGINIA DEPT. OF ENVIRONMENTAL QUALITY; DIVISION OF AIR QUALITY	4/26/2018	6/19/2019	Natural gas-fired combined cycle power plant	Dew Point Heater	natural gas	140	MMCF/YR	Dew Point Heater (16.0 MMBTU/HR)	Sulfuric Acid (mist, vapors, etc)	Pipeline quality natural gas with a maximum sulfur content of 0.4 gr/100 scf	BACT-PSD

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Table B-1. Summary of SCR Costs - Projected Actual Emissions

Emission Unit	NO_X Emissions (tons/year)	SCR Control Efficiency	NO_X Emissions Removed (tons/year)	Total Capital Investment	Annual Cost ($/year)	Cost Effectiveness ($/ton)
B-4	24.96	90%	22.47	$4,684,522	$490,838	$21,847
B-5	10.39	90%	9.35	$4,028,726	$417,032	$44,584
H-11	31.56	90%	28.40	$4,894,235	$522,175	$18,387

Cost Estimate

U.S. Oil & Refining Co.: B-4

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) =	$4,684,522	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$45,101	in 2019 dollars
Indirect Annual Costs (IDAC) =	$445,736	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$490,838	in 2019 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 =	$23,423	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,357	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$9,951	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$9,371	in 2019 dollars
Direct Annual Cost =		$45,101	in 2019 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) =	$3,518	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$442,219	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$445,736	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$490,838	per year in 2019 dollars
NOx Removed =	22.47	tons/year
Cost Effectiveness =	$21,847	per ton of NOx removed in 2019 dollars

Cost Estimate

U.S. Oil & Refining Co.: B-5

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) =	$4,028,726	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$33,242	in 2019 dollars
Indirect Annual Costs (IDAC) =	$383,790	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$417,032	in 2019 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 =	$20,144	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$981	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$4,729	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$7,388	in 2019 dollars
Direct Annual Cost =		$33,242	in 2019 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) =	$3,478	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$380,312	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$383,790	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$417,032	per year in 2019 dollars
NOx Removed =	9.35	tons/year
Cost Effectiveness =	$44,584	per ton of NOx removed in 2019 dollars

Cost Estimate

U.S. Oil & Refining Co.: H-11

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) =	$4,894,235	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$56,629	in 2019 dollars
Indirect Annual Costs (IDAC) =	$465,546	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$522,175	in 2019 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 =	$24,471	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$2,979	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$19,316	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$9,862	in 2019 dollars
Direct Annual Cost =		$56,629	in 2019 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) =	$3,530	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$462,016	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$465,546	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$522,175	per year in 2019 dollars
NOx Removed =	28.40	tons/year
Cost Effectiveness =	$18,387	per ton of NOx removed in 2019 dollars

Table B-2. Input Data

Variable	Value			Unit
Unit ID	B-4	B-5	H-11	
Maximum Heat Input Rate [1]	99.0	80.0	105.9	MMBtu/hr
Baseline NO_X Emission Rate [1]	24.96	10.39	31.56	tons/year
Fuel HHV [2]	1,242	1,242	1,242	Btu/scf
Actual Annual Fuel Consumption [1]	311,580,125	148,088,955	604,844,535	scf/year
Days of Operation	365	365	365	days/year
Low NOX Emissions [3]	0.072	0.072	0.060	lb/MMBtu
	13.933	6.622	22.539	tons/year
Control Efficiency	44%	36%	29%	
Retrofit Factor [4]	1.5	1.5	1.5	
Interest Rate [5]	7.00%	7.00%	7.00%	
Estimated Equipment Life	20	20	20	years

[1] Site-Specific value for the U.S. Oil Tacoma Refinery. Maximum heat input rate represents the rated maximum heat capacity for each unit. Baseline NO_X emissions are the projected actual emissions after implementation of significant heat recovery improvements during US Oil's upcoming 2021 turnaround..

[2] Default value provided in the EPA's Control Cost Manual and associated template calculation workbook for various control technologies.

[3] LNB Emission rates based on preliminary estimates obtained from vendors.

[4] A retrofit factor of 1.5 is applied to the costs to account for the additional challenges of retrofitting a low-NOx burner in an existing heater. Actual retrofit costs, assuming a retrofit is technically feasible, may be even higher.

[5] See "Note on Interest Rates Used in Cost Effectiveness Calculations," Appendix B.

Table B-3. LNB Direct Capital Costs

Cost	B-4	B-5	H-11	Notation
Purchased Equipment Costs [1]				
Ultra Low-NOX Burner Unit	$120,000	$100,000	$157,050	A
Instrumentation	$12,000.0	$10,000.0	$15,705.0	0.1 * A
Sales Tax	$3,600.00	$3,000.00	$4,711.50	0.03 * A
Freight	$6,000.00	$5,000.00	$7,852.50	0.05 * A
Subtotal, Purchased Equipment Cost	$141,600	$118,000	$185,319	PEC
Direct Installation Costs [1]	$150,000	$150,000	$250,000	DI
Total Direct Cost	**$291,600**	**$268,000**	**$435,319**	DC = PEC + DI

[1] LNB capital and installation costs are based on preliminary vendor estimates. Additional engineering and design evaluation is required to determine cost and feasibility for each individual emission unit, which is expected to result in additional costs for implementation of the retrofits.

Table B-4. LNB Indirect Capital Costs

Cost	B-4	B-5	H-11	Notation
Overhead & Contingencies				
Engineering	$14,160	$11,800	$18,532	0.1 * PEC
Construction & Field Expenses	$7,080	$5,900	$9,266	0.05 * PEC
Contractor Fee	$14,160	$11,800	$18,532	0.1 * PEC
Start-Up	$2,832	$2,360	$3,706	0.02 * PEC
Performance Testing	$1,416	$1,180	$1,853	0.01 * PEC
Contingencies	$4,248	$3,540	$5,560	0.03 * PEC
Total Indirect Cost	**$43,896**	**$36,580**	**$57,449**	

[1] Indirect installation costs developed using methods consistent with the "OAQPS Control Costs Manual," Chapter 3, U.S. EPA, Innovative Strategies and Economics Group. Table 3.8. Research Triangle Park, NC. December 1995.

Total Capital Investment (TCI)	**$503,244**	**$456,870**	**$739,152**

Table B-5. LNB Direct Annual Costs

Variable	Value			Units
Hours per Year	8760	8760	8760	hours
Operating Labor	N/A	N/A	N/A	
Maintenance	N/A	N/A	N/A	
Total Direct Annual Costs	**$0**	**$0**	**$0**	

Table B-6. LNB Indirect Annual Costs

Cost	B-4	B-5	H-11	Notation
Administrative Charges	$10,065	$9,137	$14,783	0.02 * TCI
Insurance	$5,032	$4,569	$7,392	0.01 * TCI
Property Tax	$5,032	$4,569	$7,392	0.01 * TCI
Capital Recovery	$47,503	$43,125	$69,771	CRF * TCI
Total Indirect Annual Cost	**$67,632**	**$61,400**	**$99,337**	

Table B-7. LNB Cost Summary

Variable	B-4	B-5	H-11	Units
Total Annualized Cost	$67,632	$61,400	$99,337	2020$/year
Emission Rate Prior to Burner Replacement	24.96	10.39	31.56	tons NO_X/yr
Pollutant Removed	11.03	3.77	9.02	tons NO_X/yr
Cost Per Ton of Pollutant Removed	$6,131	$16,282	$11,018	$/ton

A Note on the Interest Rate Used in the Cost-Effectiveness Calculations

The cost analyses in this report follow OMB's guidance by using an interest rate of 7% for evaluating the cost of capital recovery, as discussed below.

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[6]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[7] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[8] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. Interest rates for smaller energy companies such as Par Petroleum (owner of U.S. Oil) can be higher than those for larger companies. In its 2019 annual report, Par Petroleum indicated that it has currently issued bonds with interest rates paying between 5.00% and 7.75%. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%. "As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."[9]

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[6] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[7] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[8] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[9] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

EPA SCR Model

Company	EMI acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	1	MMBtu/hr	HHV	Fuel scf/yr	NPHR	Elevation
MMBtu/hr												
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033	2,120,038,722	8.2	400
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300	1,033	2,544,046,467	8.2	400
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400	1,033	3,392,061,955	8.2	400
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500	1,033	4,240,077,444	8.2	400
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033	5,088,092,933	8.2	400
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033	5,936,108,422	8.2	400
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033	6,784,123,911	8.2	400

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers	Empty	Slip ppm	Vol
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK
365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2	UNK

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr	max scf/yr
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250	2,120,038,722
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	300	2,544,046,467
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	400	3,392,061,955
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	500	4,240,077,444
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600	5,088,092,933
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700	5,936,108,422
UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800	6,784,123,911

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536	1,031	121
2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft	14.5	1	0.1536	1,237	145
3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft	14.5	1	0.1536	1,649	193
4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft	14.5	1	0.1536	2,062	241
5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536	2,474	289
5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536	3,299	386

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint
3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944	437,150	25,425
3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697	159,162	340,729	499,890	28,623
3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805	208,560	410,249	618,808	34,509
3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106	257,459	473,874	731,333	39,896
3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165	839,156	44,915
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649
3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252	$642,253	1,044,505	54,150

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

										Capital $		Annualized	
Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm
20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150	197	2,218	20,340	44	2,186	3.8
24,812	91,348	14,378	159,162	2,971	337,757	340,729	499,890	237	2,114	19,082	41	1,666	3.6
33,083	121,798	19,171	208,560	3,042	407,207	410,249	618,808	315	1,962	17,255	37	1,547	3.3
41,353	152,247	23,963	257,459	3,107	470,767	473,874	731,333	394	1,855	15,958	34	1,463	3.2
49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774	14,972	32	1,399	3.0
57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9
66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656	13,538	29	1,306	2.8

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
EPA SCR Model

			IR 5.5	IR %
Number of units	TAC	MMBtu/hr	$/ton	
9	437,150	250	2,785	80%
0	499,890	300	2,485	85%
2	618,808	400	2,298	85%
0	731,333	500	2,166	86%
0	839,156	600	2,065	86%
3	943,315	700	1,985	86%
2	1,044,505	800	1,919	86%

acfm	MMBtu/hr
4	250
3.597849783	300
3.340303242	400
3.158165035	500
3.019820357	600
2.909702152	700
2.819099124	800

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

Refineries Regional Haze Review - Tesoro

Controls

Company	EMI acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	1	MMBtu/hr	HHV
MMBtu/hr									
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300	1,033
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400	1,033
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500	1,033
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033

CCU CO BOILERS (F-302 & F-304)	335,843	937							
MMBtu/hr (Model input)	acfm	tpy	Exhasut Temp F	Industial	Natual Gas	Retrofit	Factor	MMBtu/hr	HHV
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033
Adjusted 700	1.04	937	650	Industial	Natual Gas	Retrofit	1.00	725.15	1,033
Adjusted 800	0.91	937	650	Industial	Natual Gas	Retrofit	1.00	725.15	1,033
Tesoro information									

F 102 CRUDE HEATER	41,590	164							
MMBtu/hr (Model input)	acfm	tpy	Exhasut Temp F	Industial	Natual Gas	Retrofit	Factor	MMBtu/hr	HHV
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033
Tesoro information			650	Industial	Natual Gas	Retrofit	1.00	120	906
	Design acfm	Max tpy NOx							
F 201 VACUUM FLASHER HEATER	35,684	64							
F 6650 CAT REFORMER HEATER	44,716	130							
F 6651 CAT REFORMER HEATER	51,017	138							
F 751 MAIN BOILER	67,931	225							
F 752 MAIN BOILER	68,674	189							

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
2,544,046,467	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
3,392,061,955	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
4,240,077,444	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
6,784,123,911	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
6,784,123,911	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
6,149,351,583	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3
6,149,351,583	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,069,103,758	8.2	23	365	365	0.27	0.015	1.05	52,560	25	19.5	58.39	14	NH3

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
									0.45						

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03
3	1	10	UNK	UNK	650	55,577	592.1	5.5	3.513	0.03	227	60	4	0.005	0.03

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT	ELEVF
250	2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft
300	2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft
400	3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft
500	4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft
600	5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft
700	5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft
800	6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft

MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF
700	5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft
800	6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft
700	6,149,351,583	6,149,351,583	0.82	1	8,760	90	571.71	1.13	335,843	112	0.00890364	Less 500ft
800	6,149,351,583	6,149,351,583	0.82	1	8,760	90	571.71	1.13	335,843	112	0.00890364	Less 500ft

MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF
250	2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft
120	1,160,264,901	1,069,103,758	0.82	0.921	8072	94.5	125.68	1.18	6,381,721	19,760.72	0	

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020

Refineries Regional Haze Review - Tesoro

P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
14.5	1	0.1536	1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927
14.5	1	0.1536	1,237	145	3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697
14.5	1	0.1536	1,649	193	3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805
14.5	1	0.1536	2,062	241	3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106
14.5	1	0.1536	2,474	289	3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013
14.5	1	0.1536	2,887	338	3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730
14.5	1	0.1536	3,299	386	3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094

P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
14.5	1	0.1536	2,887	338	3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730
14.5	1	0.1536	3,299	386	3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094
14.5	1	0.1536	2,990	350	3.85	402	20	52	51	175	23	7,873	0.0745	373	10,286,436
14.5	1	0.1536	2,990	350	3.85	402	21	52	51	175	23	7,886	0.0745	373	9,816,751
										340					114,030,975

11.62

P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
14.5	1	0.1536	1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927
14.5	1	0.1452	322.95	6,648	1	7,645	87.4	41	17	87	11	3,800	0.0745	164	20,876,000
															20,629,000
															30,806,000
															30,806,000
															20,613,000
															13,999,000

4.11

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC
134,206	302,944	437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150
159,162	340,729	499,890	28,623	24,812	91,348	14,378	159,162	2,971	337,757	340,729	499,890
208,560	410,249	618,808	34,509	33,083	121,798	19,171	208,560	3,042	407,207	410,249	618,808
257,459	473,874	731,333	39,896	41,353	152,247	23,963	257,459	3,107	470,767	473,874	731,333
305,991	533,165	839,156	44,915	49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156
354,238	589,078	943,315	49,649	57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315
402,252	$642,253	1,044,505	54,150	66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC
354,238	589,078	943,315	49,649	57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315
402,252	$642,253	1,044,505	54,150	66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505
366,963	610,239	977,202	51,432	59,974	220,803	34,754	366,963	3,340	606,900	610,239	977,202
364,614	582,159	946,774	49,084	59,974	220,803	32,853	364,614	2,971	579,188	582,159	946,774
			570,155	1,340,590	209,997	116,845	2,237,587			8,510,405	10,747,992
				22.35		3.56					

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC
134,206	302,944	437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150
462,549	1,559,143	2,021,692	104,380	315,021	39,600	3,548	462,549	3,881	1,555,262	1,559,143	2,021,692
				15.24	0.52	0.30					
											1,813,706
											2,906,872
											2,906,872
											1,798,805
											1,249,990

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

		Capital $		Annualized					
NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC	MMBtu/hr	$/ton
197	2,218	20,340	44	2,186	3.8	9	437,150	250	2,785
237	2,114	19,082	41	1,666	3.6	0	499,890	300	2,485
315	1,962	17,255	37	1,547	3.3	2	618,808	400	2,298
394	1,855	15,958	34	1,463	3.2	0	731,333	500	2,166
473	1,774	14,972	32	1,399	3.0	0	839,156	600	2,065
552	1,709	14,185	31	1,348	2.9	3	943,315	700	1,985
631	1,656	13,538	29	1,306	2.8	2	1,044,505	800	1,919

NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm				
552	1,709	14,185	31	1,348	2.9				
631	1,656	13,538	29	1,306	2.8				
843	1,159	14,695	32	1,396	3.0				
843	1,123	12,271	26	1,183	2.6				
747	14,381		340		32.0				

NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	EPA $/ton			
197	2,218	20,340	44	2,186	3.8	2,962			
126	16,086	173,967	502	16,847	49				
		est 200 MMBtu/hr	est EPA flow	est 200 MMBtu/hr	est EPA flow				
51	35,279	103,145	178	9,069	15.66	7,589			
137	21,196	154,030	266	14,534	25.11	3,736			
137	21,196	154,030	266	14,534	25.11	3,520			
179	10,060	103,065	178	8,994	15.54	2,159			
170	7,349	69,995	121	6,250	10.80	2,570			

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Tesoro

	acfm	MMBtu/hr
80%	4	250
85%	3.597849783	300
85%	3.340303242	400
86%	3.158165035	500
86%	3.019820357	600
86%	2.909702152	700
86%	2.819099124	800

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

Refineries Regional Haze Review - BP Cherry Point Controls

Company	EMI acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	1	MMBtu/hr	HHV
MMBtu/hr									
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300	1,033
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400	1,033
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500	1,033
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033

#1 REFORMER HEATERS	323,119	338		698					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1.00	700	1,033
Adjusted to 338 tpy									
BP's est									

CRUDE HEATER	288,473	472		623					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1.00	600	1,033
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1.00	700	1,033
Adjusted 700	1.04		650	Industrial	Natural Gas	Retrofit	1.00	600	1,033
Adjusted 800	0.89		650	Industrial	Natural Gas	Retrofit	1.00	700	1,033
BP's est									

REFORMING FURNACE #1 (N H2 PLANT) * two	297,077	124		321					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033
Adjusted 300	1.07		650	Industrial	Natural Gas	Retrofit	1.00	600	1,033
Adjusted 400	0.92		650	Industrial	Natural Gas	Retrofit	1.00	700	1,033
BP est									

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers
2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
2,544,046,467	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
3,392,061,955	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
4,240,077,444	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
6,784,123,911	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers
5,936,108,422	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers
5,088,092,933	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3
5,936,108,422	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3
5,282,001,378	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3
5,282,001,378	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3

Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers
5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3
5,282,001,378	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3
5,282,001,378	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	300
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	400
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	500
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800

Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700

Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	623
1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	623

Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	623
1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	623

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536	1,031	121
2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft	14.5	1	0.1536	1,237	145
3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft	14.5	1	0.1536	1,649	193
4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft	14.5	1	0.1536	2,062	241
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536	2,474	289
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536	3,299	386

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536	2,474	289
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
5,282,001,378	5,282,001,378	0.82	1	8,760	90	491	1.13	288,473	112	0.00890364	Less 500ft	14.5	1	0.1452	2,568	300
5,282,001,378	5,282,001,378	0.82	1	8,760	90	491	1.13	288,473	112	0.00890364	Less 500ft	14.5	1	0.1452	2,568	300

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536	2,474	289
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
5,282,001,378	5,282,001,378	0.82	1	8,760	90	491	1.13	288,473	112	0.00890364	Less 500ft	14.5	1	0.1452	2,568	300
5,282,001,378	5,282,001,378	0.82	1	8,760	90	491	1.13	288,473	112	0.00890364	Less 500ft	14.5	1	0.1452	2,568	300

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent
3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944	437,150	25,425	20,677
3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697	159,162	340,729	499,890	28,623	24,812
3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805	208,560	410,249	618,808	34,509	33,083
3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106	257,459	473,874	731,333	39,896	41,353
3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165	839,156	44,915	49,624
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895
3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252	$642,253	1,044,505	54,150	66,165

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895
										94,809,582	1,093,077			420,048	284,001
										9.55					4.91

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent
3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165	839,156	44,915	49,624
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895
4	346	19	52	44	150	20	6,748		320	9,325,358	317,653	553,484	871,136	46,627	51,515
3	346	18	52	44	150	20	6,763		320	8,835,561	315,204	524,167	839,370	44,178	51,515
										94,809,582	1,093,077			420,048	284,001
										10.73					5.51

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent
3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165	839,156	44,915	49,624
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895
4	346	19	52	44	150	20	6,748		320	9,325,358	317,653	553,484	871,136	46,627	51,515
3	346	18	52	44	150	20	6,763		320	8,835,561	315,204	524,167	839,370	44,178	51,515
										143,325,183	860,731			479,126	125,031
										#REF!					#REF!

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020

Refineries Regional Haze Review - BP Cherry Point

Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	Capital $ MMBtu/hr	acfm	Annualized MMBtu/hr	acfm	Number of units
76,124	11,982	$134,206	2,933	300,011	302,944	437,150	197	2,218	20,340	44	2,186	3.8	9
91,348	14,378	159,162	2,971	337,757	340,729	499,890	237	2,114	19,082	41	1,666	3.6	0
121,798	19,171	208,560	3,042	407,207	410,249	618,808	315	1,962	17,255	37	1,547	3.3	2
152,247	23,963	257,459	3,107	470,767	473,874	731,333	394	1,855	15,958	34	1,463	3.2	0
182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774	14,972	32	1,399	3.0	0
213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3
243,595	36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656	13,538	29	1,306	2.8	2

Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	Capital $ MMBtu/hr	acfm	Annualized MMBtu/hr	acfm	
213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3
						943,315	304	3,101					
120,961	180,467	1,093,077				7,827,719	321	24,378	135,442	292	11,182	24	
0.57	5.38												

Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	Capital $ MMBtu/hr	acfm	Annualized MMBtu/hr	acfm	
182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774	14,972	32	1,399	3.0	0
213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3
189,659	29,852	317,653	3,288	550,196	553,484	871,136	425	2,051					
189,659	29,852	315,204	2,869	521,298	524,167	839,370	425	1,976					
120,961	180,467	1,093,077				7,827,719	321	24,378	135,442	292	11,182	24	
0.64	6.05												

Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	Capital $ MMBtu/hr	acfm	Annualized MMBtu/hr	acfm	
182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774	14,972	32	1,399	3.0	0
213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3
189,659	29,852	317,653	3,288	550,196	553,484	871,136	141	6,161					
189,659	29,852	315,204	2,869	521,298	524,167	839,370	141	5,936					
103,461	65,513	860,731				11,038,382	141	78,065	238,875	516	18,397	40	
#REF!	#REF!					#REF!							

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - BP Cherry Point

TAC	MMBtu/hr	$/ton			acfm	MMBtu/hr
437,150	250	2,785	80%		4	250
499,890	300	2,485	85%		3.597849783	300
618,808	400	2,298	85%		3.340303242	400
731,333	500	2,166	86%		3.158165035	500
839,156	600	2,065	86%		3.019820357	600
943,315	700	1,985	86%		2.909702152	700
1,044,505	800	1,919	86%		2.819099124	800

943,315	700	1984.836455	0.861167325	2.909702152	700

$/ton					
839,156	600	2064.984213	0.85906912	3.019820357	600
943,315	700	1984.836455	0.861167325	2.909702152	700

$/ton					
839,156	600	2,065	86%	3.019820357	600
943,315	700	1,985	86%	2.909702152	700
7,806					
7,521					

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

Refineries Regional Haze Review - Shell

Controls

Company	EMI acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	1	MMBtu/hr
MMBtu/hr								
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800

FCCU REGENERATOR UNIT (INCLUDES COB/WGS BYPASS)	348,722	578.74	753.1791948					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1.00	700
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1.00	800
Adjusted 700	1.08	594	650	Industrial	Natural Gas	Retrofit	1.00	752.95
Adjusted 800	0.94	594	650	Industrial	Natural Gas	Retrofit	1.00	752.95
No data from Shell								

BOILER #1 ERIE CITY--31G-F1	70,001	199	151					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr
250	115,784	179	650	Industrial	Natural Gas	Retrofit	1	200
Shell								
MMBtu/hr (Model input)	42,349	76.53	91.46727031					
CRU #2 HTR, INTERHTR--10H-101,102,103	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr
250	115,784	69	650	Industrial	Natural Gas	Retrofit	1	200
Shell								
Shell	Cogen turbine 1 MW							
Shell	Cogen turbine 2 MW							
Shell	Cogen turbine 3 MW							

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
1,033	2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	2,544,046,467	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	3,392,061,955	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	4,240,077,444	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
1,033	6,784,123,911	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
1,033	5,936,108,422	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3
1,033	6,784,123,911	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3
1,033	6,385,174,042	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3
1,033	6,385,174,042	8.2	400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
1,033	2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3
HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3
1,033	2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	300
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	400
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	500
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800
3	1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	700
3	1	2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	800

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250

Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536	1,031	121
2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft	14.5	1	0.1536	1,237	145
3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft	14.5	1	0.1536	1,649	193
4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft	14.5	1	0.1536	2,062	241
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536	2,474	289
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536	3,299	386

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536	2,887	338
6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536	3,299	386
6,385,174,042	6,385,174,042	0.82	1	8,760	90	594	1.13	348,722	112	0.00890364	Less 500ft	14.5	1	0.1452	3,105	363
6,385,174,042	6,385,174,042	0.82	1	8,760	90	594	1.13	348,722	112	0.00890364	Less 500ft	14.5	1	0.1452	3,105	363

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536	1,031	121

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF	Cat vol	Cat ft2
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536	1,031	121

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent	Elec
3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944	437,150	25,425	20,677	76,124
3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697	159,162	340,729	499,890	28,623	24,812	91,348
3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805	208,560	410,249	618,808	34,509	33,083	121,798
3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106	257,459	473,874	731,333	39,896	41,353	152,247
3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165	839,156	44,915	49,624	182,696
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895	213,146
3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252	$642,253	1,044,505	54,150	66,165	243,595

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent	Elec
3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078	943,315	49,649	57,895	213,146
3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252	642,253	1,044,505	54,150	66,165	243,595
3.85	418	20	52	53	182	24	8,175	0.0745	387	10,680,913	381,036	633,642	1,014,677	53,405	62,274	229,270
3.85	418	21	52	53	182	24	8,188	0.0745	387	10,193,215	378,597	604,485	983,082	50,966	62,274	229,270

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent	Elec
3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944	437,150	25,425	20,677	76,124
										11,420,745		1,916,288	2,053,888	57,104	17,221	23,935
										2.25						0.31

Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC	TAC	Maint	Reagent	Elec
3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944	437,150	25,425	20,677	76,124
										5,939,772			635,480	29,699	6,165	22,464
										1.17						0.30

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

								Capital $		Annualized			
Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC
11,982	$134,206	2,933	300,011	302,944	437,150	197	2,218	20,340	44	2,186	3.8	9	437,150
14,378	159,162	2,971	337,757	340,729	499,890	237	2,114	19,082	41	1,666	3.6	0	499,890
19,171	208,560	3,042	407,207	410,249	618,808	315	1,962	17,255	37	1,547	3.3	2	618,808
23,963	257,459	3,107	470,767	473,874	731,333	394	1,855	15,958	34	1,463	3.2	0	731,333
28,756	305,991	3,167	529,998	533,165	839,156	473	1,774	14,972	32	1,399	3.0	0	839,156
33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3	943,315
36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656	13,538	29	1,306	2.8	2	1,044,505

Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	TAC EPA model	$/ton
33,548	354,238	3,224	585,854	589,078	943,315	552	1,709	14,185	31	1,348	2.9	3	943,315
36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656	13,538	29	1,306	2.8	2	1,044,505
36,086	381,036	3,468	630,174	633,642	1,014,677	521	1,948	15,258	33	1,450	3.1	1,014,677	1,948
34,113	378,597	3,085	601,400	604,485	983,082	521	1,887	12,742	28	1,229	2.7		

Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	TAC EPA model	$/ton
11,982	$134,206	2,933	300,011	302,944	437,150	179	2,441	20,340	44	2,186	3.8	9	437,150
39,340	137,600				2,053,888	164	12,511.00					Note 8 yrs life	

3.28

Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	TAC EPA model	$/ton
11,982	$134,206	2,933	300,011	302,944	437,150	69	6,346.82	20,340	44	2,186	3.8	9	437,150
13,454	71,782			563,699	635,480	59	10,813.00						

1.12

Lower emission limit
Lower emission limit
Lower emission limit

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Shell

MMBtu/hr	$/ton			acfm	MMBtu/hr
250	2,785	80%		4	250
300	2,485	85%		3.597849783	300
400	2,298	85%		3.340303242	400
500	2,166	86%		3.158165035	500
600	2,065	86%		3.019820357	600
700	1,985	86%		2.909702152	700
800	1,919	86%		2.819099124	800

700	1984.836455	0.861167325	2.909702152	700
800	1918.878526	0.863031405	2.819099124	800

250	2,785	88%	4	250

250	2,785	228%	4	250

#REF!	#REF!

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

Refineries Regional Haze Review - Phillips 66 Controls

Company	EMI acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	1	MMBtu/hr
MMBtu/hr								
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800

FCCU/CO Boiler/Wet Gas Scrubber 4F-100, 4F-101	277,771	247	600					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600
Phillips 66 - no data								

CRUDE HEATER 1F-1	58,359	184	126					
MMBtu/hr (Model input)	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr
250	115,784	166	650	Industrial	Natural Gas	Retrofit	1	200

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf
1,033	2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	2,544,046,467	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	3,392,061,955	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	4,240,077,444	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	5,936,108,422	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56
1,033	6,784,123,911	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf
1,033	5,088,092,933	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56

HHV	Fuel scf/yr	NPHR	Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf
1,033	2,120,038,722	8.2	400	365	365	0.20	0.02	1.05	52,560	25	29	56

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

storage day	NH3	Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60

storage day	NH3	Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60

storage day	NH3	Layers	Empty	Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr
14	NH3	3	1	2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

Op hrs	MCF	ACF	MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT
4	0.005	0.03	250	2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364
4	0.005	0.03	300	2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364
4	0.005	0.03	400	3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364
4	0.005	0.03	500	4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364
4	0.005	0.03	600	5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364
4	0.005	0.03	700	5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364
4	0.005	0.03	800	6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364

Op hrs	MCF	ACF	MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT
4	0.005	0.03	600	5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364

Op hrs	MCF	ACF	MMBtu/hr	max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT
4	0.005	0.03	250	2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

ELEVF	P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
Less 500ft	14.5	1	0.1536	1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927
Less 500ft	14.5	1	0.1536	1,237	145	3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697
Less 500ft	14.5	1	0.1536	1,649	193	3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805
Less 500ft	14.5	1	0.1536	2,062	241	3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106
Less 500ft	14.5	1	0.1536	2,474	289	3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013
Less 500ft	14.5	1	0.1536	2,887	338	3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730
Less 500ft	14.5	1	0.1536	3,299	386	3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094

ELEVF	P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
Less 500ft	14.5	1	0.1536	2,474	289	3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013

ELEVF	P	RF	FWF	Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI
Less 500ft	14.5	1	0.1536	1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927
																16,615,487
																3.27

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy
134,206	302,944	437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150	197
159,162	340,729	499,890	28,623	24,812	91,348	14,378	159,162	2,971	337,757	340,729	499,890	237
208,560	410,249	618,808	34,509	33,083	121,798	19,171	208,560	3,042	407,207	410,249	618,808	315
257,459	473,874	731,333	39,896	41,353	152,247	23,963	257,459	3,107	470,767	473,874	731,333	394
305,991	533,165	839,156	44,915	49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156	473
354,238	589,078	943,315	49,649	57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315	552
402,252	$642,253	1,044,505	54,150	66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505	631

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy
305,991	533,165	839,156	44,915	49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156	473

DAC	IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy
134,206	302,944	437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150	166
			83,077	17,691	46,045	18,680	269,398			1,572,499	1,944,651	159
					0.60	1.56						

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Phillips 66

$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC	MMBtu/hr	$/ton		acfm	MMBtu/hr
2,218	20,340	44	2,186	3.8	9	437,150	250	2,785	80%	4	250
2,114	19,082	41	1,666	3.6	0	499,890	300	2,485	85%	3.597849783	300
1,962	17,255	37	1,547	3.3	2	618,808	400	2,298	85%	3.340303242	400
1,855	15,958	34	1,463	3.2	0	731,333	500	2,166	86%	3.158165035	500
1,774	14,972	32	1,399	3.0	0	839,156	600	2,065	86%	3.019820357	600
1,709	14,185	31	1,348	2.9	3	943,315	700	1,985	86%	2.909702152	700
1,656	13,538	29	1,306	2.8	2	1,044,505	800	1,919	86%	2.819099124	800

$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	TAC EPA model	$/ton					
1,774	14,972	32	1,399	3.0	0	839,156	600	2,065	86%	3.019820357	600

$/ton	MMBtu/hr	acfm	MMBtu/hr	acfm	TAC EPA model	$/ton					
2,639.80	20,340	44	2,186	3.8	9	437,150	250	2,785	95%	4	250
12,225.13									2	7	

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

Refineries Regional Haze Review - US Oil Controls

Company	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV	Fuel scf/yr	NPHR
CB Project	150000		650	Industrial	Natural Gas	Retrofit	1.00	324	1033	2,746,532,184	8.2
MMBtu/hr											
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033	2,120,038,722	8.2
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300	1,033	2,544,046,467	8.2
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400	1,033	3,392,061,955	8.2
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500	1,033	4,240,077,444	8.2
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033	5,088,092,933	8.2
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033	5,936,108,422	8.2
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033	6,784,123,911	8.2

Company	acfm	tpy	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV	Fuel scf/yr	NPHR
MMBtu/hr											
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1.00	200	1,033	2,120,038,722	8.2
US Oil H11											

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers	Empty
400	365	365	0.570780491	0.057078049	1.05	24,000	25	29	56	14	NH4	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1

Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers	Empty
400	365	365	0.2	0.02	1.05	52,560	25	29	56	14	NH3	3	1

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
2	UNK	UNK	650	484	541.7	5.5	0.293	0.0676	227	60	4	0.005	0.03	324
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	300
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	400
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	500
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800

Slip ppm	Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
2	UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF
2,746,532,184	2,746,532,184	0.82	1.00	8,760	90	729	1.13	150,000	99	0.0101	Less 500ft	14.5	1.00	0.3157
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536
2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft	14.5	1	0.1536
3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft	14.5	1	0.1536
4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft	14.5	1	0.1536
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536
6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx redut tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC
1,509	156	4.22	180	13	54	65	223	30	10100	0.0745	167	6,016,879	241,194	451,247
1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944
1,237	145	3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697	159,162	340,729
1,649	193	3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805	208,560	410,249
2,062	241	3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106	257,459	473,874
2,474	289	3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991	533,165
2,887	338	3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238	589,078
3,299	386	3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252	$642,253

Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC	IDAC
1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206	302,944
												4,894,235		465,546

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton
692,440	30,084	76,447	98,619	36,044	241,194	2,989	448,258	451,247	692,440	729	950
437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150	197	2,218
499,890	28,623	24,812	91,348	14,378	159,162	2,971	337,757	340,729	499,890	237	2,114
618,808	34,509	33,083	121,798	19,171	208,560	3,042	407,207	410,249	618,808	315	1,962
731,333	39,896	41,353	152,247	23,963	257,459	3,107	470,767	473,874	731,333	394	1,855
839,156	44,915	49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774
943,315	49,649	57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709
1,044,505	54,150	66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656

TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton
437,150	25,425	20,677	76,124	11,982	134,206	2,933	300,011	302,944	437,150	197	2,217.91
522,175	24,471	2,979	19,316	9,862					522,175	28	18,649
		2937.324742	0.25						437,150	28	15,612.51
		6.94								7.04	

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - US Oil

MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC	MMBtu/hr		
18,578	40	2,138	4.6		692,440	323.8775966		
20,340	44	2,186	3.8	9	437,150	250		
19,082	41	1,666	3.6	0	499,890	300		
17,255	37	1,547	3.3	2	618,808	400		
15,958	34	1,463	3.2	0	731,333	500		
14,972	32	1,399	3.0	0	839,156	600		
14,185	31	1,348	2.9	3	943,315	700		
13,538	29	1,306	2.8	2	1,044,505	800		

MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC	$/ton
20,340	44	2,186	3.8	9	437,150	250

Refineries Regional Haze Review - Notes

BP & Tesoro - Capital cost 5-12 times EPA Model
Electrical cost about 50% of EPA model
BP & Tesoro reagent cost 5-25 times EPA Model
Catalyst cost 2-6 times the EPA Model

Cost 200 MMBtu/hr (Region X input)						
yrs	25	30	25	30	30	
int	5.5	5.5	3	3	3	
reconstruction factor	1	1	1	1	1.5	
Cost	480,333	453,878	401,461	371,757	501,852	1.35
		0.94	0.84	0.77	1.04	

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

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	acfm @ 650 F	tpy - reduced	Exhaust Temp F	Industrial	Natural Gas	Retrofit	Factor	MMBtu/hr	HHV	Fuel scf/yr	NPHR
MMBtu/hr											
250	115,784	197	650	Industrial	Natural Gas	Retrofit	1	200	1,033	2,120,038,722	8.2
300	138,941	237	650	Industrial	Natural Gas	Retrofit	1	300	1,033	2,544,046,467	8.2
400	185,255	315	650	Industrial	Natural Gas	Retrofit	1	400	1,033	3,392,061,955	8.2
500	231,569	394	650	Industrial	Natural Gas	Retrofit	1	500	1,033	4,240,077,444	8.2
600	277,883	473	650	Industrial	Natural Gas	Retrofit	1	600	1,033	5,088,092,933	8.2
700	324,197	552	650	Industrial	Natural Gas	Retrofit	1	700	1,033	5,936,108,422	8.2
800	370,510	631	650	Industrial	Natural Gas	Retrofit	1	800	1,033	6,784,123,911	8.2
Equipment											
Comparison											

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

Elevation	Days - SCR	Days-Unit	Inlet lb/MMBtu	Outlet lb/MMBtu	SRF	Cat hrs	SCR life	Reg %	lb/cf	storage day	NH3	Layers	Empty	Slip ppm
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2
400	365	365	0.20	0.02	1.05	52,560	25	29	56	14	NH3	3	1	2

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

Vol	acfm	Temp F	Ft3/min-MMBtu/hr	CEPCI	AI	$/gal	$/KWH	Cat $/cf replacement	Lab $/hr	Op hrs	MCF	ACF	MMBtu/hr
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	250
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	300
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	400
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	500
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	600
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	700
UNK	UNK	650	484	541.7	3.25	0.293	0.0676	227	60	4	0.005	0.03	800

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020

Refineries Regional Haze Review - Checklist

max scf/yr	act scf/yr	HRF	CF	SCR hrs	NOx EF	NOx reduct tpy	NRF	acfm	Vspace	RT	ELEVF	P	RF	FWF
2,120,038,722	2,120,038,722	0.82	1	8,760	90	197	1.13	115,784	112	0.00890364	Less 500ft	14.5	1	0.1536
2,544,046,467	2,544,046,467	0.82	1	8,760	90	237	1.13	138,941	112	0.00890364	Less 500ft	14.5	1	0.1536
3,392,061,955	3,392,061,955	0.82	1	8,760	90	315	1.13	185,255	112	0.00890364	Less 500ft	14.5	1	0.1536
4,240,077,444	4,240,077,444	0.82	1	8,760	90	394	1.13	231,569	112	0.00890364	Less 500ft	14.5	1	0.1536
5,088,092,933	5,088,092,933	0.82	1	8,760	90	473	1.13	277,883	112	0.00890364	Less 500ft	14.5	1	0.1536
5,936,108,422	5,936,108,422	0.82	1	8,760	90	552	1.13	324,197	112	0.00890364	Less 500ft	14.5	1	0.1536
6,784,123,911	6,784,123,911	0.82	1	8,760	90	631	1.13	370,510	112	0.00890364	Less 500ft	14.5	1	0.1536

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

Cat vol	Cat ft2	Cat height of layer	Area	l/W	height	Reag lb/hr	lb/hr	gal/hr	tank gal	crf	Elc - KW	TCI	DAC
1,031	121	3.85	139	12	52	17	60	8	2,800	0.059	129	5,084,927	134,206
1,237	145	3.85	166	13	52	21	72	10	3,300	0.059	154	5,724,697	159,162
1,649	193	3.85	222	15	52	28	96	13	4,400	0.059	206	6,901,805	208,560
2,062	241	3.85	277	17	52	35	121	16	5,500	0.059	257	7,979,106	257,459
2,474	289	3.85	333	18	52	42	145	19	6,500	0.059	309	8,983,013	305,991
2,887	338	3.85	388	20	52	49	169	23	7,600	0.059	360	9,929,730	354,238
3,299	386	3.85	444	21	52	56	193	26	8,700	0.059	411	10,830,094	402,252

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

IDAC	TAC	Maint	Reagent	Elec	Cat	DAC	AC	CR	IDAC	TAC	NOx removed tpy	$/ton
				NW 50%								
302,944	437,150	25,425	20,677	76,124	11,982	$134,206	2,933	300,011	302,944	437,150	197	2,218
340,729	499,890	28,623	24,812	91,348	14,378	159,162	2,971	337,757	340,729	499,890	237	2,114
410,249	618,808	34,509	33,083	121,798	19,171	208,560	3,042	407,207	410,249	618,808	315	1,962
473,874	731,333	39,896	41,353	152,247	23,963	257,459	3,107	470,767	473,874	731,333	394	1,855
533,165	839,156	44,915	49,624	182,696	28,756	305,991	3,167	529,998	533,165	839,156	473	1,774
589,078	943,315	49,649	57,895	213,146	33,548	354,238	3,224	585,854	589,078	943,315	552	1,709
$642,253	1,044,505	54,150	66,165	243,595	36,244	402,252	3,278	638,976	642,253	1,044,505	631	1,656

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020
Refineries Regional Haze Review - Checklist

MMBtu/hr	acfm	MMBtu/hr	acfm	Number of units	TAC	MMBtu/hr	
20,340	44	2,186	3.8	9	437,150	250	2,785
19,082	41	1,666	3.6	0	499,890	300	2,485
17,255	37	1,547	3.3	2	618,808	400	2,298
15,958	34	1,463	3.2	0	731,333	500	2,166
14,972	32	1,399	3.0	0	839,156	600	2,065
14,185	31	1,348	2.9	3	943,315	700	1,985
13,538	29	1,306	2.8	2	1,044,505	800	1,919

EPA Cost Control Estimates Compared to Refinery Estimates for SCR 8/18/2020

Refineries Regional Haze Review - Summary

Summary	**Capital $**	**Annualized $/yr**	1,000 BPD	Annualized $/gallon
BP	32,490,281	3,630,825	242	0.0010
Tesoro	32,822,017	3,405,599	119	0.0019
Shell	15,228,478	1,649,340	145	0.0007
66	13,381,398	1,415,885	105	0.0009
Total	93,922,174	10,101,648	611	0.0011