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February 16, 2021
HSE 450.015 (Regional Haze)

Re: Phillips 66 Comments on Ecology's Draft Regional Haze SIP Revision Four Factor Analysis

- **Sent online via WA Dept. of Ecology Comment Portal**
- **Sent via email to Philip Gent and Colleen Stinson by request**

Dear Mr. Gent,

The Phillips 66 Ferndale Refinery (P66) appreciates that the Washington Department of Ecology has solicited comments on the proposed Draft Regional Haze SIP Revision Four Factor Analysis (FFA). With these comments, P66 shares a few broad areas of concern, specific concerns related to the P66 FCCU and the 1F-1 Crude Heater, and a few other specific questions about the FFA.

Broadly Applicable Concerns

P66 Distance-weighted Point Source Emissions (Q/d)

The Ferndale refinery's distance-weighted point source emissions (Q/d) is only 10.9, barely above the Regional Haze threshold of 10. The scope of the request should match the effect of the emissions, and Ecology's request to retrofit the 1F-1 Crude Heater and the FCCU significantly exceed the reduction necessary to decrease P66's Q/d to below 10.

Ecology's Cost Estimates Significantly Underestimate Costs

Within the time allowed by Ecology during spring 2020, P66 developed cost estimates consistent with the methods provided in the EPA Air Pollution Control Cost Manual (CCM). P66 presented this site-specific FFA to Ecology on June 29, 2020. Per the CCM, the methodology presented in the manual "can provide cost estimates that are more accurate when using detailed site-specific information."[1] This fact holds particularly true when the design of a given control is highly-site specific, as is the case with SCR.[2] The CCM methodologies, specifically those used in the cost calculation spreadsheet, were initially created for use in the electric utility generating sector, and as such do not correlate well with costs incurred for generally smaller SCR installations on heaters, boilers, and FCCUs in use at refineries. As such, P66 elected to use site-specific estimates developed by vendors and scaled the cost estimates based on the heat rating of each individual unit considered. This method is used to estimate the costs of capital projects and yields highly accurate cost estimates.

Capital cost estimates provided by Ecology do not appear to cover all capital costs involved in installing SCR on an existing heater or FCCU. Costs often overlooked in this context include piping, stack retrofits to accommodate SCR catalyst beds, upgrades to blowers and fans to maintain sufficient air flow to overcome the backpressure induced by the addition of the catalyst system, and costs associated with derating the heater or FCCU to accommodate SCR, rerouting piping, and making room at ground-level for the SCR equipment by moving other equipment. Each of these factors, even when identified as a specific cost category in the cost manual, require consideration of site-specific factors, and thus a generic cost estimation does not sufficiently capture the complexities of an SCR retrofit.

Ecology's FFA notes that Ecology could not reconcile cost differences between the P66 FFA and their own. They also note that "limited supporting information" was provided as part of the P66 FFA. P66 reached out to Ecology several times to offer to review the P66 FFA and supporting calculations in more detail, but Ecology did not respond.

P66 believes that the effort that went into the June 2020 P66 FFA represents a more realistic cost estimate for all sources at the Ferndale Refinery, and once again entreats Ecology to enter into a conversation with the refinery about the basis of these cost estimates.

Ecology's Assumptions Unclear

Specific data showing Ecology's assumptions and costs is needed to understand Ecology's cost estimates for controls. The Western States Petroleum Association (WSPA) submitted a formal Public Records Request Public Records Request (P003975-012221) requesting that Ecology provide this information so that we can better understand the basis of Ecology's cost estimates. Unfortunately, Ecology's response indicates that this data will not be provided to WSPA until March 1, 2021, rendering us unable to respond to specific assumptions and cost estimates

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[1] EPA Air Pollution Control Cost Manual Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology." Page 8. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[2] EPA Air Pollution Control Cost Manual Section 4, Chapter 2, "Selective Catalytic Reduction." Page 53. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

during this comment period. P66 will issue an update to this letter including our analysis once Ecology's cost analysis is made available.
Ecology states in the report that its cost analysis was based on an interest rate of 3.25 percent. This rate does not reflect realistic costs of borrowing. P66's four-factor analysis included a discussion supporting a more realistic interest rate of 7 percent. A 7 percent interest rate is both consistent with historical EPA policy, and is consistent and the Office of Management and Budget guidance for regulatory analysis. Use of the lower percentage leads to an underestimation of the total costs, since the current prime rate is exceptionally and does not represent the expected interest rate over the life of the equipment.

Ecology's Dollar-Per-Ton NOx Reduction Threshold Unclear
Ecology's FFA indicates a range of costs that the agency considers cost effective at the five Washington refineries. These range from a low of $1,300/ton to a high of $7,600/ton. However, Ecology's report does not identify the cost effectiveness threshold used to determine whether a control technology is cost effective, or information supporting use of that particular threshold as representing reasonably available control technology (RACT).

Selective Catalytic Reduction
<u>SCR is not RACT</u>
SCR as RACT is not supported by evidence available in the RACT/BACT/LAER Clearinghouse (RBLC). To our knowledge, SCR has not been required as RACT anywhere in the country outside of California, where there are extreme ozone nonattainment areas. SCR may sometimes be required as Best Available Control Technology (BACT) on large heaters, or as Lowest Achievable Emission Rate (LAER) for major projects in nonattainment areas. While the 4-factor analysis approach uses a similar top-down process as a BACT review, a RACT level of control is not expected to be as stringent or expensive as BACT.

<u>Ecology Failed to Scale SCR Costs</u>
SCR in particular is not a bolt-on, one-size-fits all control. It is highly dependent upon the size of the catalyst bed and the amount of ammonia injected, both of which add significant costs when it comes to both installation as well as ongoing maintenance. Ecology's estimates do not appear to have accounted for these differences in sizing and how they affect SCR costs. This likely accounts for some of the difference between the capital costs provided by refineries in their FFAs versus Ecology's capital costs as estimated using only the EPA CCM. More specifically, Ecology appears to assume the same capital cost for heaters and FCCUs of differing sizes at different facilities, which further emphasizes the point that Ecology failed to scale SCR costs, as demonstrated by costs included in Ecology's FFA.

<u>Ammonia Impacts from SCR</u>
Ecology has failed to account for ammonia (NH_3) emissions associated with the use of SCR. Washington regulates ammonia as a toxic air pollutant in WAC 173-460. An assessment of the impacts of this air toxic is appropriate and should be incorporated into Ecology's final FFA. Ammonia is also a precursor for condensable particulate matter (PM), and Ecology appears to have failed to consider the impact of SCR on PM emissions.

Regional Haze Rulemaking Should Be Fair and Equitable

P66 expects that Ecology will establish emission reduction requirements that result in both an equivalent reduction in visibility impacts between source categories and an equitable usage of capital between source categories. We also expect that Ecology will require equitable expenditure of capital and visibility improvement between sources in any single source category. No industry category or specific facility should have to expend significantly more resources or be required to generate significantly more reductions than other members of a source category or other industrial source categories. P66's emissions contribute to regional haze, but Ecology's own information indicates that industrial sources are not the major contributor to regional haze in Washington – instead, the major contributor to regional haze in Washington is transportation emissions. As such, no single industry will be able, and should not be expected to provide all reductions required to meet the national goal of no anthropogenic visibility impact in Class I Areas by 2064.

Despite significant differences in Q/d for the Washington refineries, a roughly equivalent capital expenditure was requested by Ecology of all Washington refineries except US Oil. Ecology's estimates of the capital expenditures required ranged from 14 million to 28 million. Failing to account for the relative impact of expenditures on the visibility improvements that might be achieved has the result of requiring P66 to carry more than our fair share of the cost burden during this Regional Haze planning period, despite our minimal impact on visibility.

Refinery	Size (1000 BPD)	Q/d	Ecology's Estimated Capital Costs of Recommended Retrofits	Capital Cost per Q/d Impact	Retrofits Recommended in Regional Haze FFA?
BP	242	36.4	$28,580,446	$785,177	Yes
Tesoro	119	30.7	$15,371,363	$500,696	Yes
Shell	145	24.5	$20,850,767	$851,052	Yes
P66	105	10.9	$14,067,940	$1,290,637	Yes
US Oil	41	3.2	0	0	No

Ecology Did Not Take into Account Improvements Made Since 2008

During a presentation at the P66 refinery in May 2019, Scott Inloes requested and received information about refinery NOx, SO_2 and PM improvements related to recent rulemakings (NSPS Ja, Refinery Sector Rule, etc.), lower fuel sulfur standards, and EPA Consent Decrees or other enforcement actions. These represent significant reductions in emissions, many of which occurred within the last planning period. Ecology's original Regional Haze rulemaking effort, as explained by Scott Inloes' in May 2019, specifically noted that Ecology would take these other reductions in regional haze-causing emissions into account when performing the Regional Haze FFA. P66 provided a summary of these improvements to Scott Inloes via email. This email is included as an enclosure to these comments. Ecology's FFA does not appear to have accounted for these in-place reductions, resulting in an inaccurate assessment of actual controls installed at refineries since 2008.

Flexibility

Flexibility in Projects

RCW 70A.15.2230 does not prescribe a specific type of emission reduction required of a source or a source category. P66 would appreciate flexibility with regard to how required emission reductions are to be accomplished. P66 may want to implement projects that were not deemed cost effective by the FFA or required by Ecology's rule/orders, or may want to implement projects for other business reasons that would provide equivalent or greater reductions, but which do not involve the emission units named Ecology's FFA.

Flexibility in Timing

Regional Haze regulations are not prescriptive when it comes to the timing of implementation of any reductions identified for the 2021 SIP submittal. Neither do those regulations or EPA's guidance prescribe the form that those emission reduction requirements must take. Ecology should make use of the inherent flexibility afforded by both state and federal laws and regulations when it comes to emission reduction requirements Ecology identifies as required at P66, to allow the refinery to minimize unnecessary downtime and cost.

Flexibility in Emissions Reductions

Similar to the comment made above regarding project flexibility, P66 would appreciate the flexibility to determine the most cost-effective method of NOx reduction in consultation with Ecology, even if that reduction is not the source or the method that Ecology identified in the FFA. No equivalent reductions in NOx should be considered off the table when it comes to the RACT rulemaking process.

Specific Equipment

Ferndale Refinery Fluidized Catalytic Cracking Unit (FCCU)

The Phillips 66 Refinery's FCCU is one of the newest FCCU's in the country, went through prevention of significant deterioration (PSD) permitting for its installation, and was retrofitted with enhanced selective non-catalytic reduction (ESNCR) NOx control in 2010 as a requirement of the ConocoPhillips Consent Decree with EPA. The ESNCR system functions by injecting vaporized ammonia enhanced with hydrogen into the combustion chamber of the CO Boiler. The ammonia reacts with nitrogen oxide (NO) in the combustion zone converting it to gaseous nitrogen (N_2). The NOx reductions were required by the Consent Decree and the associated federally enforceable requirement under PSD 00-02 Amendment 7 and its subsequent revisions, and the FCCU's ESNCR was determined to be BACT for NOx control by Ecology as recently as 2015 (Ecology PSD 00-02 Amendment 8, Finding 26). Ecology's own analysis in PSD 00-02 as recently as 2015 (Ecology PSD 00-02 Amendment 8, Finding 26) indicates that the P66 FCCU's ESNCR is considered Best Available Control Technology (BACT), a significantly higher bar than should be expected as a result of Ecology's reasonable available control technology (RACT) Regional Haze rulemaking.

In a letter to P66 dated November 27, 2019, Ecology formally requested "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 your facility that has not been retrofitted since 2005." Since Ecology's November 27, 2019 information request only included FCCUs that had not been retrofitted since 2005, the P66 FCCU is out of scope for the 2018 – 2028 planning period because it was retrofitted in 2010 with ESNCR for NOx control. P66 has provided a copy of Ecology's information request for reference as enclosure 1. P66 responded to Ecology's information request with a list of subject equipment in January 2020, a FFA in April 2020, and an updated FFA in June 2020. In each of these submittals, P66 identified that its FCCU did not meet Ecology's criteria for inclusion in the FFA, and Ecology had not questioned that determination, requested clarification, or requested a FFA for the FCCU.

It is inappropriate to include P66's recently retrofitted, BACT-controlled FCCU in Ecology's Regional Haze State Implementation Plan revisions during this planning period. P66's FCCU was out of scope for Ecology's Regional Haze information request and Ecology's own recent PSD permit for this FCCU indicates that ESNCR is considered BACT for NOx control, so P66 did not include the FCCU our response to Ecology's information request. Further, the Federal Land Manager expressed their concurrence for exemption emissions units modified after 2005, as presented on page 13 of Ecology's response to the FLM's comments.

1F-1 Crude Heater
Ecology's cost estimate for retrofitting the 1F-1 Crude Heater significantly underestimates actual costs, particularly capital costs. P66 respectfully requests that Ecology meet with Ferndale staff to discuss the significant differences between Ecology's costs as estimated using the EPA CCM as compared to the costs estimated by P66 in June 2020.

P66 is very much concerned that a retrofit of this heater with SCR is technically infeasible due to the lack of plot space in the unit and other concerns related to existing equipment that would need to be changed out to accommodate SCR operations. Whether SCR is technically feasible at this location given the lack of plot space remains an outstanding question that P66 will endeavor to answer before Ecology's rulemaking.

Summary

In summary, we have significant concerns with Ecology's FFA report. We have outlined and discussed these concerns in this letter for Ecology's consideration and future discussion. P66's primary concerns are:

- Many of the assumptions and methods in Ecology's analysis are unclear;
- Ecology's control cost estimates appear to be based on an "one size fits all" approach and underestimates true costs, particularly at a smaller refinery such as the Ferndale Refinery;

- The application of SCR to Crude Heater 1F-1 may not be technically feasible, and even if technically feasible, would result in controls that are more stringent and more costly than RACT; and
- Ecology also incorrectly includes P66's FCCU as an affected souce in the report.

P66 would like to refute the assertion Ecology made during our call today that holding a one-on-one meeting with any individual refinery gives the impression of impropriety. This reticence to meet with industry during the Regional Haze assessment process stymied Ecology's understanding of the FFAs presented by the refineries. As a result, Ecology used EPA's inaccurate CCM rather than reviewing the vendor quotes and engineering estimates used to prepare the refineries' FFAs. To prevent repeating this mistake as Ecology's RACT rulemaking proceeds, P66 requests that Ecology use data provided by Washington refineries and analyze that data in a transparent process that includes an assessment of total installed costs as estimated by the refineries, technical feasibility, siting considerations, vendor guaranteed control efficiencies, and other environmental impacts when evaluating the reasonableness of all control technologies. If necessary, data can be provided in an aggregated or blinded form to ensure equitable treatment of all refineries subject to the RACT rulemaking.

P66 looks forward to working with Ecology as Ecology proceeds with RACT rulemaking as it pertains to the 1F-1 Crude Heater.

Please feel free to contact Erin Strang at (360) 384-8217 or erin.t.strang@p66.com to discuss the Phillips 66 Ferndale Refinery's concerns with Ecology's Regional Haze Rulemaking effort.

Sincerely,

P. David Klanica

Enclosures:

1. Phillips 66 June 29, 2020 Ferndale Refinery Four Factor Analysis
2. Ecology's Regional Haze PowerPoint Presentation (Regional Haze 2021 - Refinery (NSPS Ja) May 2019.pptx)
3. Ecology PSD 00-02 Amendment 8
4. Ecology's November 27, 2019 Information Request
5. Email regarding emissions reductions in the previous planning period entitled "RE Phillips 66 Regional Haze Information Request"

Enclosure 1

Phillips 66 June 29, 2020 Ferndale Refinery Four Factor Analysis

John L. Andersen

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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:

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June 2020

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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]

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[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.

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[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

[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.

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[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	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)	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 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	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
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	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
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	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
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:

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 - "

Enclosure 2

Ecology's Regional Haze PowerPoint Presentation (Regional Haze 2021 - Refinery (NSPS Ja) May 2019.pptx)

Regional Haze 2021 Plan – Refineries (Heaters & FCCU)

Toby Mahar/Scott Inloes
NWCAA/Air Quality Program

May 2019

DEPARTMENT OF ECOLOGY
State of Washington

1

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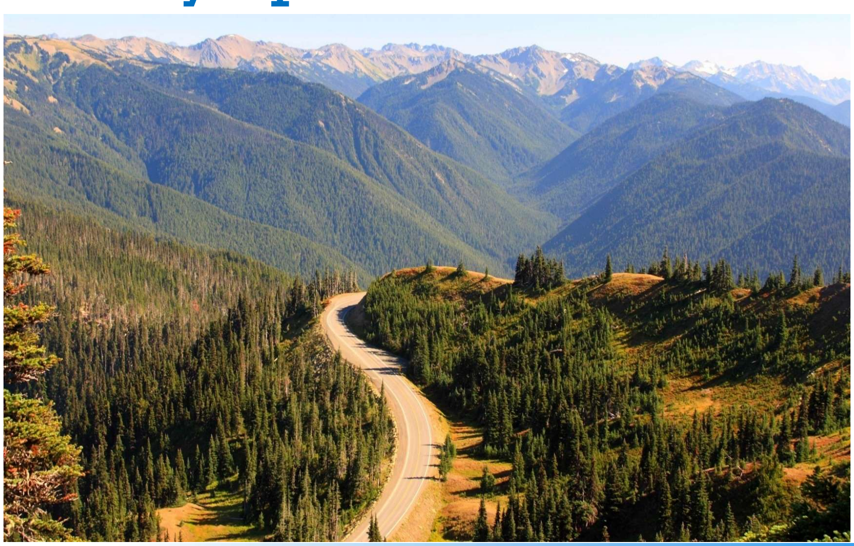
Olympic National Park



2

2

Agenda

- History (Emissions & BART)
- Regional Haze 2021 Plan
- Heaters & FCCU's (RACT vs NSPS Ja trigger)
- Modeling input files
- Document refineries procedures to identify NSPS Ja triggers
- Future plans

3

3

Regional Haze Plan – BART (2010)

- BP Cherry Point Refinery (Ferndale)
  - New source review Best Available Control Technology (BACT)
  - Recently issued federal Maximum Achievable Control Technology (MACT)
  - Recent federal Consent Decree requirements
  - Note: Low NOx Burners were on consider due to derating the heaters
- Tesoro Refining and Marketing (Anacortes)
  - Proposed NOx reductions on three heaters – Low NOx Burners(<$4,000/ton of NOx)
  - Limit liquid fuels on one heater
  - Past projects
    - fuel sulfur reductions
    - PM reductions from FCCU
  - FIP modified the BART order – sulfur reduction for NOx reductions

4

4

2021 Regional Haze Plan

- Goals
  - Development of control strategies to meet nation visibility goal and show reasonable progress – CAA 169A and 169B (40 CFR 51.308)
  - https://www.epa.gov/visibility
  - https://www.epa.gov/sites/production/files/2018-09/documents/regional_haze_reform_roadmap_memo_09-11-2018.pdf
- Levels
  - Visibility reductions to "Natural conditions" by 2064
- Review – Q/D greater than 10
- RACT or 4 factor analysis
  - Coal Power Plant
  - Aluminum
  - Refineries – Heaters/FCCU
  - Others

RACT

- RACT is defined in the Revised Code of Washington (RCW) **70.94.030(20)** as: "…the lowest emission limit that a particular source or source category is capable of meeting by the application of control technology that is **reasonably available** considering technological and economic feasibility. RACT is determined on a case-by-case basis for an individual source or source category taking into account:
- The impact of the source upon air quality,
- The availability of additional controls,
- The emission reduction to be achieved by additional controls,
- The impact of additional controls on air quality, and
- The capital and operating costs of the additional controls.

RACT

- Pulp and Paper Mills
- BART (BP and Tesoro)
- Cost covered by Facilities
- Information request
  - Equipment status and configuration
  - Add on equipment
  - Review cost and possible requirements to install equipment
  - Tesoro BART recommended conversion of three heaters during the 2021 Regional Haze plan
  - Cost in developing the NSPS Ja rule less than $3,000/ton

NSPS Ja

- One page sheet with status
- Facility to estimate future changes by 2028
- One day of time
- Information already on site
- Minimal cost
- Review procedures
- Additional request if warranted

Modeling Files

- Baseline – Current impacts (2014 & 2017)
- Expected impacts by 2028 (Due Dec 2019)
- Refineries
  - Confirm stack conditions
  - Confirm any reductions (2007-2028)

Regional Haze Plan - History

Source Information		Plantwide Emissions (tpy)				Crude unloading Emission (tpy)		Non Crude unloading Emission (tpy)			Reduction tpy each 10 yrs	Heaters only NSPS Ja levels	Heaters Only Site Duty Btu/hr	less than NSPS Ja
Facility Name	Emission year	NOx	SO2	PM/PM10	Q/D	NOx	SO2	NOx	SO2	NOx & SO2	TPY	MMBtu/hr	MMBtu/hr	%
Total	2009	6,002	3,095	607		266	946	5,736	2,046	7,782				
Total	2016	5,866	1,203	568		144	31	5,722	1,174	6,895		2,359	10,067	23%
Total	2028	5,399	1,183	568		205	31	5,194	1,153	6,346				
Total	2038	5,066	1,159	568		205	31	4,861	1,129	5,990				
Total	2048	4,595	1,081	568		205	31	4,390	1,051	5,441				
Total	2058	4,124	1,003	568		205	31	3,919	972	4,892				
Total	2064	3,653	925	568		205	31	3,448	894	4,342				
2016-2028								471	78	549				
2016-2064								2,274	279	2,553				

Regional Haze Plan - History

Source Information		Plantwide Emissions (tpy)				Crude unloading Emission (tpy)		Non Crude unloading Emission (tpy)			Reduction tpy each 10 yrs	Heaters only NSPS Ja levels	Heaters Only Site Duty Btu/hr	less than NSPS Ja
Facility Name	Emission year	NOx	SO2	PM/PM10	Q/D	NOx	SO2	NOx	SO2	NOx & SO2	TPY	MMBtu/hr	MMBtu/hr	%
BP Cherry Point Refinery	2009	2,228	2,134	170		76	650	2,152	1,484	3,636				
	2016	1,905	781	168	36.4	24	10	1,881	771	2,652		953	4,631	21%
Reductions	2028					50	10	1,711	750	2,461	191			
										-				
Tesoro Refining and Marketing Co	2009	1,795	404	172		15	66	1,780	338	2,118				
	2016	2,020	125	165	30.7	6	2	2,014	123	2,137		248	2,044	12%
Reductions	2028					10	2	1,782	123	1,905	232			
Conoco-Phillips	2009	705	182	43		95	45	610	34	644				
	2016	769	45	58	10.9	47	11	722	34	756		112	1,714	7%
Reductions	2028					71	11	662	34	696	60			
Puget Sound Refining Company	2009	1,156	370	222		80	185	1,076	185	1,261				
	2016	1,109	246	177	24.5	67	8	1,042	238	1,280		1,046	1,679	62%
Reductions	2028					74	8	976	238	1,214	66			
U.S. Oil & Refining Company	2009	118	5	12				118	5	123				
	2016	63	7	11	3.2			63	7	70				
Reductions	2028					-	-	63	7	70				

2021 Regional Haze Plans – NSPS Ja

- Document data
  - Units subject to NSPS Ja
  - Regulation Prorogated May 2007 (Nov 2012 stay lifted)
  - Heaters greater than 40 MMBtu/hr (NOx & SO2)
  - FCCU (NOx, SO2, PM, CO)
  - Ecology letter – Informing the sources they are subject to review for reduction

NSPS Ja Data

- NSPS Ja
  - List of unit subject or not
  - Preheaters
  - Review refineries procedures to identify NSPS triggers
  - 2-5 heaters selected to review projects and documentation
  - Heater Engineer
  - Project Team

Regional Haze Plan - Refineries

- Number of heaters
  - Btu/hr capacity
    - Capacity subject to NSPS Ja
    - Capacity not subject to NSPS Ja
      - 60 ppm or less
      - Greater than 60 ppm
  - Modification
    - 2010-2018
    - Estimated reduction by 2028
  - New Units
    - 2010-2018
    - 2019-2028

Public Meetings

- September?
  - Past reduction
  - Expected reduction
  - Refineries
    - NSPS Ja potential reductions
    - Expected RACT/NSPS Ja reduction
    - Regulatory orders
  - Past PSD permit – National Park Service Modeling

15

15

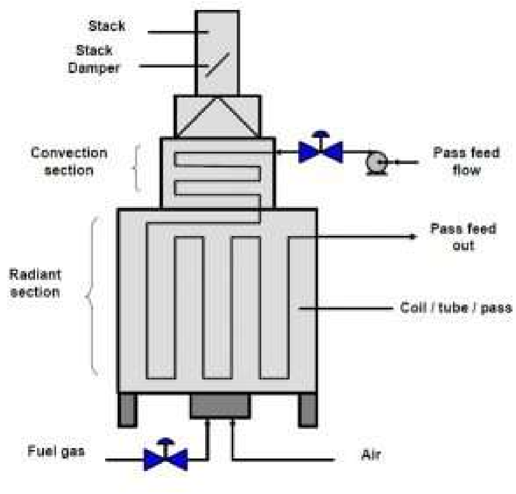
RACT?

- NSPS Ja units
  - FCCU - 3
  - Larger Heaters – 5
  - Half of the SO_2 and NOX emissions
  - EPA preamble cost less than $5,000/ton of NOx

16

16

Refinery Heater



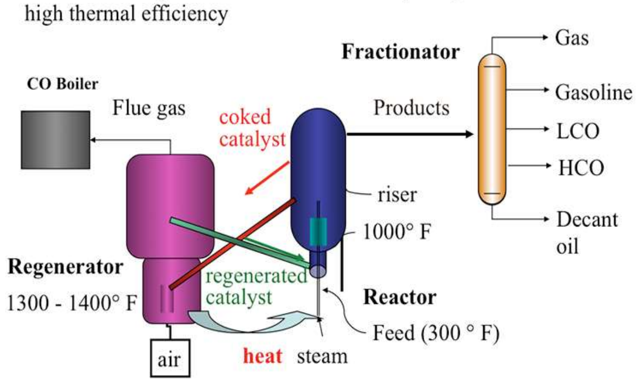
17

17

Fluid Catalytic Cracking Unit

Fluid Catalytic Cracking (FCC)

- Introduced in 1942
- Excellent integration of reactor with catalyst regenerator for high thermal efficiency



18

18

NSPS Modification

- NSPS Modification
- Hourly change in emissions per 40 CFR 60.14
- § 60.14 Modification.

- This determination should be based on maximum hourly emissions prior to the project and the maximum hourly emission after the project. The FCCU determination and 2005 documents indicated that the determination should be based on the best data: CEM or source test data before and after the change.
-
- The following references support this determination:

- Federal Register, Vol. 36, No. 247 – Thursday, December 23, 1971 - 24376
- Federal Register, Vol. 39, No. 200 – Tuesday, October 15, 1974 - 36946
- Federal Register, Vol. 57, No. 140 – Tuesday, July 21, 1992 - 32316
- Federal Register, Vol. 70, No. 202 – Thursday, October 20, 2005 – 61081
- https://cfpub.epa.gov/adi/index.cfm?fuseaction=home.dsp_show_file_contents&CFID=88423596&CFTOKEN=19113037&id=0200060

Future Regional Haze Plans (2028+)

- Update Information on heaters & FCCU
- Document which units are subject to NSPS Ja
- Evaluate other options – RACT or 4 factor analysis?

PSD Issues

- Emission Unit –
  - Per project
  - Based on NSPS/MACT, Unit?
  - Electronic companies – site wide
  - All activities during a maintenance period – per unit
  - Example – Additional distillation column (Down steam impacts - PTE or Projected actuals)
- Support facilities - Emissions
- New EPA Guidance (Ecology is not supporting the use)
- Questions?

21

21

Backup

22

22

Enclosure 3

Ecology PSD 00-02 Amendment 8

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

September 15, 2015

Mr. Daniel R. Toperosky
HSE Manager
Phillips 66 Ferndale Refinery
P.O. Box 8
Ferndale, WA 98248

Re: Phillips 66 Final Determination PSD-00-02, Amendment 8

Dear Mr. Toperosky:

Enclosed is the final determination for PSD-00-02, Amendment 8 and an updated Technical Support Document.

The permit, or any conditions contained in it, may be appealed to the Pollution Control Hearings Board as provided in Chapter 43.21B RCW and Chapter 371-08 WAC.

If you have any questions, please contact me at (360) 407-6812 or robert.burmark@ecy.wa.gov.

Sincerely,

Robert C. Burmark

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program

rcb/tc

Enclosures 2

By certified mail

cc: Tonnie Cummings, NPS
Don Dossett, EPA
Rick Graw, USFS
Christopher Hanlon-Meyer, Ecology
Dan Mahar, NWCAA
Rosanne Paris, Phillips 66
Don Shepherd, NPS

RECEIVED SEP 2 1 2015

[Note to non-applicant recipients of this letter: Because a public comment period, and response to comments summary was not required for this administrative permit revision, a preliminary determination described in WAC 173-400-740(2) was provided only to the applicant per WAC 173-400-730(2)(b)(ii)].

WASHINGTON STATE DEPARTMENT OF ECOLOGY
POST OFFICE BOX 47600
OLYMPIA, WASHINGTON 98504-7600

IN THE MATTER OF:	]	
	]	**NO. PSD-00-02, Amendment 8**
Phillips 66	]	
Ferndale Refinery	]	**FINAL APPROVAL**
P.O. Box 8	]	**OF PSD APPLICATION**
Ferndale, Washington 98248-0008	]	

This approval (Amendment 8) is issued pursuant to the regulations set forth in the Washington Administrative Code 173-400-700. All previous approvals were issued pursuant to the United States Environmental Protection Agency (EPA) regulations for the Prevention of Significant Deterioration (PSD) set forth in Title 40, Code of Federal Regulations, Part 52, and regulations set forth in the Washington Administrative Code 173-400-141 or 173-400-700 beginning in 2005. Based upon the Notice of Construction Application (NOC) for PSD-00-02, Amendment 8 dated April 23, 2015, submitted by Phillips 66 the Washington State Department of Ecology (Ecology), now finds the following:

FINDINGS

1. Amendment 8 is an administrative amendment that requests additional language changes so that the permit better reflects current operations under the refinery's 2005 federal Clean Air Act based Consent Decree. Several Consent Decree requirements were of a temporary nature to allow the refinery to reach certain compliance goals. Now that those conditions have been satisfied, they are no longer applicable or needed. No permit limits are affected.

2. Amendment 7 was an administrative amendment that accomplished the following three changes: reflected the facility owner's name change from the ConocoPhillips Company to Phillips 66; expanded Condition 2 for the Fluidized Catalytic Cracking Unit (FCCU) and carbon monoxide (CO) boiler to include a consent decree short-term nitrogen oxides (NO_X) limit of 123.2 ppmvd at 0 percent O_2 (7-day rolling average); and also expanded Condition 2 to include consent decree long term NO_X limit of 96.1 ppmvd at 0 percent O_2 (365-day rolling average).

3. Amendment 6 was an administrative amendment that corrected a mistake in the wording that defined the flexibility of the time period between the annual tests required by existing Approval Conditions 13 and 14. The existing time period wording was incompatible with annual testing periods. There were no changes to the required testing interval or required test methods. ConocoPhillips (now Phillips 66) requested this change in a letter dated May 18, 2011, as a part of their Title V permit renewal process.

4. Amendment 5 was an administrative amendment. Approval Condition 14 was changed from semi-annual to annual testing, and Approval Condition 21b was changed to submit testing reports within 30 days of the end of the month. ConocoPhillips (now Phillips 66) requested this amendment because they identified a discrepancy between this approval and the EPA Consent Decree.

5. Amendment 4 was an administrative amendment, extending the compliance date for Approval Condition 7 from December 31, 2006, until June 30, 2007. This compliance date was based upon an EPA Consent Decree. ConocoPhillips (now Phillips 66) requested this amendment because they had difficulty scheduling the on-site construction of this project.

6. Amendment 3 was based upon an increase in throughput from the FCCU from a nominal 30,000 barrels per day (bpd) to a nominal 35,000 bpd and an increase of FCCU coke burn rate to 29,000 lb/hr. Although the permit application stated that particulate matter (PM) would not exceed the PSD Significant Emission Rate (SER), the facility had not been able to demonstrate compliance with the PM and particulate matter smaller than 10 microns in diameter (PM_{10}) emission limits for the FCCU established in Northwest Clean Air Agency's (NWCAA's) Order of Approval to Construct (OAC #733a). Including PM in the permit modification restricted emissions from the project to below the significance levels for PM and PM_{10}, thereby avoiding the requirements of the PSD program for PM and PM_{10}. In addition, it was discovered that CO was incorrectly removed from the permit as part of Amendment 1. CO was added back into the permit as a result of this action.

7. Amendment 2 was an administrative amendment that changed the company name and simplified the performance testing requirements in Approval Condition 2. On April 21, 2003, Ecology was informed that the performance test method specified in Approval Condition 2 limited the source test to one specific testing procedure. Ecology agreed to change the reference; thus allowing more flexibility in performance testing.

8. Amendment 1 was based upon the application received on January 28, 2002, and determined to be complete on March 14, 2002. The amendment proposed the S Zorb process (licensed by ConocoPhillips; now Phillips 66) as a replacement for the recently permitted hydrodesulfurizer. In addition to the S Zorb replacement, two heaters (heavy HCC gasoline stripper reboiler and the heavy FCC gasoline HDS feed heater) were combined into one heater (cat gasoline desulfurizer feed heater). Removing the two heaters resulted in emissions of CO below the PSD significance rates. CO emissions were no longer contained in this PSD permit. No emission increases were associated with this amendment.

9. The original permit was based upon an application received on April 26, 2000, and determined to be complete on August 8, 2000. Below is a description of the project.

10. Amendment 3 added new Approval Conditions 4, 5, 6, 7, 8, 9, 12, 13, 14, 15, and 16.

11. Phillips 66 operates an oil refinery in Ferndale, Washington.

12. The original project consisted of two smaller projects. The Ferndale Upgrade Project and the Clean Fuels Project.

13. The Ferndale Upgrade Project consisted of installing a new nominally 30,000 bpd FCCU (now estimated at 35,000 bpd), CO boiler, and alkylation unit feed treater. The gas plant was modified to accommodate the new flow from the FCCU.

14. The Clean Fuels Project involved revamping the existing No. 2 hydrofiner to treat the light straight-run gasoline. Additionally, a new nominally 17,500 bpd cat gasoline desulfurizer was constructed to treat fluidized catalytic cracked naphtha, and a new Merox contactor to treat the light fluidized catalytic cracked naphtha.

15. These projects are subject to the following New Source Performance Standards (NSPS): Subpart Db (Standards of Performance or Industrial – Commercial – Institutional Steam Generating Units) and Subpart J (Standards of Performance for Petroleum Refineries).

16. Phillips 66 (FNA: ConocoPhillips) is one of the 28 source categories subject to PSD permitting if potential emissions of a criteria pollutant exceed 100 tons per year (tpy).

17. Phillips 66 (FNA: ConocoPhillips) is a major stationary source that emits more than 100 tons of pollutants per year.

18. Amendment 3 qualified as a major modification because NO_X, CO, and PM_{10} have a "significant" emissions increase greater than 40, 100, and 15 tpy, respectively.

19. Even though the emission increase of PM is below the PSD significant emission rate of 25 tpy, PM emission limits are included in this permit.

20. The emissions of all other air pollutants from the proposed modification are subject to review under Chapter 173-400 WAC and Chapter 173-460 WAC by the NWCAA.

21. In the original permit, ConocoPhillips (now Phillips 66) elected to take a federally enforceable limit on the natural gas fired in the CO boiler limiting the boiler to an annual capacity factor of 10 percent for natural gas. This annual capacity factor exempts the boiler from the standards for NO_X emissions under 40 CFR 60.44b(a) and 60.44b(e).

22. Several of the heaters are not able to reach their full capabilities due to undersized burners. Emissions from those units have been calculated below the units rated potential. The limitations are listed in Appendix A to this permit.

23. The project in Amendment 3 resulted in an increase of up to 499.63 tpy of NO_X.

24. An ultralow low NO_X burner has been determined to be Best Available Control Technology (BACT) for the control of NO_X from the cat gasoline desulfurizer feed heater.

25. Proper operation has been determined to be BACT for the control of NO_X from the FCCU.

26. Selective Non-Catalytic Reduction has been determined to be BACT for the control of NO_X from auxiliary firing from the CO boiler.

27. Good operating practices have been selected as BACT for the control of NO_X from the sulfur recovery unit.

28. The project in Amendment 3 resulted in a net emissions increase of up to 332.4 tpy of CO.

29. A thermal oxidizer (CO boiler) has been selected to be BACT for control of CO emissions from the FCCU.

30. Good Combustion Practices has been determined to be BACT for the control of CO from the CO boiler.

31. Good Combustion Practices has been selected to be BACT for the control of CO emissions from the SRU.

32. The project in Amendment 3 resulted in a net emissions increase of up to 29.54 tpy of PM_{10}.

33. The project in Amendment 3 resulted in a net emissions increase of up to 10.14 tpy of PM.

34. A wet gas scrubber has been selected to be BACT for controlling PM/PM_{10} emissions from the FCCU.

35. The project is located in an area that has been designated Class II for the purposes of PSD evaluation and is located approximately 75 km from the North Cascades National Park and 100 km from the Glacier Peak Wilderness Area, the nearest Class I areas.

36. The project is located in an area that is currently designated in attainment for all national air quality standards and all state air quality standards.

37. The ambient impacts of the proposed increase in emissions associated with Amendment 3 were determined with the EPA's Industrial Source Complex Prime Model and CALPUFF Model in screening mode.

38. Modeling results show that there was an increase of NO_X of approximately 0.09 micrograms per cubic meter ($\mu g/m^3$) (annual average) in the North Cascade National Park due to the original project. There is no change in the increase associated with Amendment 1 or with administrative Amendments 2, 4, 5, 6, 7 and 8.

39. Amendment 3 had no significant impact on ambient air quality.

40. The project will not have a noticeable effect on industrial, commercial, or residential growth in the Ferndale area.

41. Visibility will not be impaired in any Class 1 area due to the project.

42. Based upon the Technical Support Document originally dated April 11, 2005, for PSD-00-02, Amendment 3 (updated September 2014 to reflect administrative Amendments 4, 5, 6, and 7), and updated in August 2015 to reflect Amendment 8, Ecology finds that all requirements for PSD have been satisfied. Approval of the PSD application is granted subject to the following conditions.

APPROVAL CONDITIONS

1. Emissions of NO_X from the cat gasoline desulfurizer feed heater shall not exceed 17 ppmdv at seven percent O_2 over a 1-hour averaging period and 5.1 tpy over a 12-month rolling total. Initial compliance shall be determined in accordance with EPA Reference Method 7E.

2. Combined NO_X emissions from the FCCU and CO boiler, shall not exceed 127 ppmdv at seven percent O_2 over a 30-day rolling averaging period and 308.10 tpy over a 12-month rolling total. Phillips 66 is required to comply with the following June 3, 2014, EPA determination[1] which includes long- and short-term NO_X limits and requirements:

   a) The long-term limit shall be 96.1 ppmvd NO_X at zero percent O_2 on a 365-day rolling average basis. The long-term limit shall apply at all times (including during start-up, shutdown, and malfunction) that the FCCU and/or CO boiler are operating.

   b) The short-term limit shall be 123.2 ppmvd NO_X at zero percent O_2 on a 7-day rolling average basis. The short-term limit shall exclude periods of start-up, shutdown, and

[1] From· Phillip Brooks, Director Air Enforcement Division, EPA to. Tim Goedeker, Program Manager, US Consent Decrees, Phillips 66 Company. Re: United States el al. v. ConocoPhillips Co., NO. H-05-258 (S.D. Tex) - Final FCCU NO_X Limits for the Phillips 66 Ferndale Refinery

malfunction, but shall apply at all other times that the FCCU and/or CO boiler are operating.

c) For days in which both the FCCU and CO boiler are not operating, no NO_X values shall be used in the averages, and those periods shall be skipped in determining the 7-day and 365-day averages.

3. Emissions of NO_X from the sulfur recovery unit shall not exceed 42.2 ppmdv at seven percent O_2 over a 1-hour averaging period and 9.88 tpy. Initial compliance shall be determined by EPA Reference Method 7E.

4. Emissions of CO from the cat gasoline desulfurizer feed heater shall not exceed 0.0824 lb/MMBtu over a 1-hour averaging period and 14.4 tpy over a 12-month rolling total. Initial compliance shall be determined in accordance with EPA Reference Method 10, 10A, or 10B.

5. Combined CO emissions from the FCCU and CO boiler shall not exceed 500 ppmdv at zero percent O_2 over a 1-hour averaging period and 100 ppmdv at zero percent O_2 over a 365-day rolling average.

6. Emissions of CO from the Sulfur Recovery Unit shall not exceed 57.1 ppmdv at seven percent O_2 over a 1-hour averaging period and 8.30 tpy over a 12-month rolling total. Initial compliance shall be determined in accordance with EPA Reference Method 10.

7. Combined PM/PM_{10} emissions from the FCCU and CO boiler shall not exceed 0.50 lb/1000 lb coke burn-off over a rolling 3-hour average and 0.020 grains per dry standard cubic foot corrected to seven percent O_2 over a rolling 3-hour average.

8. Compliance with Approval Conditions 1 and 3 shall be demonstrated by yearly source testing in accordance with EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A, or an alternative approved method. Source testing shall be performed no sooner than 10 months after the previous test and no later than 13 months after the previous test.

9. Compliance with Approval Condition 2 shall be demonstrated by a continuous emission monitor for NO_X meeting the performance specifications of 40 CFR Part 60, Appendix B, and quality control/quality assurance requirements of 40 CFR Part 60, Appendix F.

10. Compliance with Approval Condition 5 shall be demonstrated by a Continuous Emission Monitor for CO meeting the performance specifications of 40 CFR Part 60, Appendix B, and quality control/quality assurance requirements of 40 CFR Part 60, Appendix F.

11. Compliance with Approval Conditions 4 and 6 shall be demonstrated by yearly source testing in accordance with EPA Reference Method 10, as found in 40 CFR Part 60,

Appendix A, or an alternative approved method. Phillips 66 will identify a surrogate parameter (such as fuel usage) and multiply it by the emission factor derived during the previous source test. Source testing shall be performed no sooner than 10 months after the previous test and no later than 13 months after the previous test.

12. Compliance with Approval Condition 7 shall be demonstrated by annual source testing in accordance with EPA Reference Method 5B, as found in 40 CFR Part 60, Appendix A, or an alternative approved method. Source testing shall be performed no sooner than 10 months after the previous test and no later than 13 months after the previous test. Source testing shall be performed at maximum normal FCCU feed rates.

13. Within 90 days of start-up, Phillips 66 shall conduct performance test for NO_X emissions from the cat gasoline desulfurizer feed heater, combined emissions from the FCCU and CO boiler and the sulfur recovery unit, conducted by an independent testing firm. A test plan shall be submitted to Ecology for approval at least 30 days prior to testing. The term start-up is defined by 40 CFR 60.2.

14. Use of natural gas shall be limited to 111,252 MMBtu/yr, over a 12-month rolling total.

15. The maximum firing rate of the cat gasoline desulfurizer feed heater, FCC combustion air heater, cat gasoline desulfurizer feed heater, CO boiler, and sulfur recover unit shall be limited to the values listed in Appendix A.

16. Within 90 days of initial start-up of the boiler, Phillips 66 shall identify boiler operational parameters and practices that have been described as "good combustion practice." These operational parameters and practices shall be included in an operation and maintenance (O&M) manual for the boiler. The O&M manual shall also include a description of records that will be maintained to insure the continuous application of "good combustion practice." The O&M manual shall be maintained by Phillips 66 and be available for review by state, federal, and local agencies. Emissions that result from a failure to follow the requirements of the O&M manual may be considered credible evidence that emission violations have occurred.

17. Phillips 66 shall report the following monitoring data to the NWCAA and Ecology. It will no longer be necessary to report to Ecology when PSD compliance and enforcement delegated NWCAA or once the NWCAA has issued a Title V permit.

    a) Submit the performance test data from the initial performance test and the performance evaluation of the continuous emission monitor's using the applicable performance specifications in 40 CFR Appendix B.

    b) Submit a report within 30 days of the end of each calendar month, or on another approved reporting schedule, and in the format approved by Ecology, including the following:

1) Calendar date.

2) Average NO_X, CO, and PM/PM_{10} emission rates from the FCC/CO boiler wet gas scrubber.

3) Identification of any steam generating days for which NO_X data were not obtained, including reasons for not obtaining sufficient data and description of corrective actions taken.

4) Identification of times emission data are excluded from the calculated average emission rate and the reasons for excluding the data.

c) Submittal of monthly reports satisfies the quarterly reporting requirements of 40 CFR 60.49b, except that Phillips 66 shall submit a quarterly report, within 30 days after the end of each calendar quarter, including the following continuous emission monitor test data:

1) Days for which data were not collected.

2) Reasons for which data were not collected.

3) Identification of times when the pollutant concentration exceeds span of the continuous emission monitor.

4) Description of any modifications to the continuous emission monitor system that could affect the ability of the system to comply with performance specifications 2 or 3.

5) Results of any continuous emission monitor drift tests.

d) In addition, Phillips 66 shall maintain monitoring records on-site for at least five years and shall submit:

1) Excess emission reports to Ecology and the NWCAA, as appropriate.
2) Results of any compliance source tests.

18. Any activity, which is undertaken by the company or others, in a manner, which is inconsistent with the application and this determination, shall be subject to enforcement under the applicable regulations.

19. Access to the source by the EPA, state, and local regulatory personnel shall be permitted upon request for the purposes of compliance assurance inspections. Failure to allow such access is grounds for an enforcement action.

20. This approval shall become invalid if construction of the project is not commenced within eighteen (18) months after receipt of the final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, unless Ecology extends the 18-month period upon satisfactorily showing that an extension is justified, pursuant to WAC 173-400-730(5).

21. A PSD permit, any conditions contained in a PSD permit, or the denial of PSD permit may be appealed to the pollution control hearings board as provided in chapter 43.21B RCW.

Prepared by:

Robert C. Burmark

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

9/10/2015
Date

ROBERT C. BURMARK
STATE OF WASHINGTON
29848
REGISTERED
PROFESSIONAL ENGINEER

Approved by:

Stuart A. Clark
Air Quality Program Manager
Washington State Department of Ecology

9/15/15
Date

APPENDIX A

Unit	WEDS ID#	Maximum Firing Rate (MMBtu/hr) Unless Otherwise Noted
Sulfur recovery unit	17	23
Cat gasoline desulfurizer feed heater	A	40
FCC combustion air heater	C	70
CO boiler	E	109*
* Applies when auxiliary firing fuel gas		

APPENDIX B

Emission Limits			
Emissions	**Cat Gas Desulfurizer Feed Heater**	**FCCU & CO Boiler**	**SRU**
NO_x	17 ppmdv & 5 1 tpy	• 123 2 ppmvd NO_x at 0% O_2 on a 7-day rolling average, • 127 ppmdv at 7% O_2 over a 30-day rolling average, • 96 1 ppmvd at 0% O_2 on a 365-day rolling average; • 308.10 tpy (12-month rolling total);	42.2 ppmdv & 9 88 tpy
CO	0 0842 lb/MMBtu & 14 4 tpy	500 ppmdv (1-hr) 100 ppmdv (365-day)	57 1 ppmdv & 8.3 tpy
PM_{10}	---	0.50 lb/1000 lb coke burned**	---

TECHNICAL SUPPORT DOCUMENT
FOR
THE PREVENTION OF SIGNIFICANT DETERIORATION
PSD-00-02, AMENDMENT 8
PHILLIPS 66
FERNDALE, WASHINGTON

September 9, 2015

1. INTRODUCTION

1.1. The Permitting Process

The Prevention of Significant Deterioration (PSD) requirements in Washington State are established in WAC 173-400-700 through 750. These rules require PSD review of all new or modified stationary sources that meet certain overall size and pollution rate criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a new or modified stationary source. The program limits degradation of air quality to that which is not considered "significant" as defined by the regulations listed above. To meet the goal of limiting degradation of air quality, the PSD rules require that an applicant utilize the most effective air pollution control equipment and procedures after considering environmental, economic, and energy factors. The program sets up a mechanism for evaluating and controlling air emissions from a proposed source to minimize the impacts on air quality, visibility, soils, and vegetation.

The location of the facility places it within the jurisdiction of the Northwest Clean Air Agency (NWCAA). The NWCAA is responsible for all air permits with the exception of PSD. The United States Environmental Protection Agency (EPA) gave authority to implement the PSD program in Washington State to the Washington State Department of Ecology (Ecology) as a SIP-approved program effective May 29, 2015.

1.2. The Project

1.2.1. The Site

Phillips 66's corporate headquarters is located in Houston, Texas. The Ferndale Refinery is located in Whatcom County on an 850-acre site, south and west of Ferndale, Washington. The refinery was built by the General Petroleum Company in 1954 and designed to process low-sulfur, light Canadian crude oil from Alberta delivered by pipeline with an original capacity of 35,000 barrels of crude oil per day. The Ferndale Refinery expanding in 1967, 1972, and 1990. In September 2002 Phillips Refining Company merged with Conoco to become ConocoPhillips, before becoming Phillips 66 in 2012 (as described in Section 1.2.2.1). "Phillips 66" will be used for the remainder of this Technical Support Document (TSD).

The Ferndale Refinery manufactures gasoline (unleaded and super unleaded), kerosene, jet fuel, low-sulfur diesel, propane, heavy fuel oil, and sulfur.

1.2.2. The Proposed Project (Amendment 8)

Phillips 66 submitted an application for Amendment 8 (dated April 23, 2015) that was received on April 28, 2015. Amendment 8 is an administrative amendment that requests additional language changes so that the permit better reflects current operations under the refinery's 2005 federal Clean Air Act based Consent Decree. Several Consent Decree requirements were of a temporary nature to allow the refinery to reach certain compliance goals. Now that those conditions have been satisfied, they are no longer applicable or needed.

Several changes were made to other permit Approval Conditions to improve their clarity. None of these changes reduced the stringency of these conditions.

Since this is an administrative amendment, no public comment period is required.

1.3. PSD Application and History of Previous Amendments

1.3.1. The original application was received on April 27, 2000, and found to be complete on August 8, 2000. PSD-00-02 was originally issued on April 4, 2001. The permit was issued for two smaller projects. The Ferndale Upgrade Project involving the installation of a new FCCU with a nominal capacity of 30,000 barrels per day (bpd), and a CO boiler. The new FCCU and CO boiler replaced the previous Thermofor Catalytic Cracking Unit and CO boiler. The gas plant was modified to accommodate the new flow from the FCCU. Finally, a new Alkylation Unit Feed Treater was installed. The Clean Fuels Project involved revamping the existing #2 Hydrofiner to treat light, straight-run gasoline. Additionally, a new Hydrodesulfurizer with a nominal capacity of 14,250 bpd was constructed to treat heavy Fluidized Catalytic Cracking naphtha. Finally, a new Merox Contactor was installed to treat light Fluidized Catalytic Cracking naphtha. These changes allowed the refinery to meet the regulatory requirements for fuel sulfur content.

1.3.2. Amendment 1: The permit was amended on June 5, 2002 (PSD-00-02 Amendment 1). The modification permitted the S Zorb process (licensed by Phillips 66 then known as ConocoPhillips) as a replacement for the previously permitted Hydrodesulfurizer. The S Zorb process operates similar to a standard hydrotreater unit using catalyst and similar equipment. Emissions from the S Zorb process remained the same as those listed in the original PSD permit. The unit had a nominal capacity of 17,250 bpd to treat Fluidized Catalytic Cracking naphtha

In addition to the S Zorb replacement, two heaters (Heavy HCC Gasoline Stripper Reboiler and the Heavy FCC Gasoline HDS Feed Heater) were combined into one heater (Cat Gasoline Desulfurizer Feed Heater). The original heaters were permitted to install Ultra Blue^{TM} Low NO_X burners. The Ultra Blue^{TM} Low NO_X burners had a design capacity of 10 parts per million (ppm) NO_X and combined emissions of 5.1 tons per year (tpy). The Cat Gasoline Desulfurizer Feed Heater has NO_X emissions of 17 ppm and 5.1 tpy. The Cat Gasoline Desulfurizer Feed Heater has the same annual tonnage of NO_X emissions (5.1 tpy) and a lower concentration (one 17 ppm emission point as opposed to two emission points of 10 ppm). Furthermore, emissions of other pollutants were reduced (12.6 tpy CO), 1.1 tpy particulate matter (PM), 4.0 tpy SO_2, and 0.8 tpy volatile organic compounds (VOCs).

Conditions that limited CO emissions were incorrectly removed from the permit during this action. No emission increases were associated with this amendment.

1.3.3. Amendment 2 was an administrative amendment that changed the company name and simplified the performance testing requirements in Approval Condition 2. On April 21, 2003, the department was informed that the performance test method specified in Approval Condition 2 limited the source test to one specific testing procedure. The department agreed to change the reference; thus allowing more flexibility in performance testing.

1.3.4. Amendment 3 (dated June 14, 2005), was a "major modification" which consisted of the following changes: increased the allowed throughput of the FCCU; added conditions to limit emissions of PM, PM smaller than 10 microns in diameter (PM_{10}); and added conditions to limit CO. The application for Amendment 3 was received on November 18, 2004. Additional information was received on December 22, 2004, and the application was found to be complete on December 23, 2004. Ecology was notified by EPA that EPA satisfied its obligations under the Endangered Species and Magnuson-Stevens Act on April 11, 2005.

1.3.4.1. FCCU: Allowed throughput of the FCCU to increase from a nominal 30,000 bpd to a nominal 35,000 bpd. Emissions of PM_{10} and CO increased above the PSD Significant Emission Rates (SERs) of 15 and 100 tpy, respectively. Therefore, conditions to limit PM_{10} and CO were added to the PSD permit.

1.3.4.2. PM and PM_{10}: Although the permit application states that PM will not exceed the PSD SER as a result of the project, the facility has not been able to demonstrate compliance with the PM and PM_{10} emission limits for the FCCU established in NWCAA's Order of Approval to Construct (OAC #733a), including those limitations intended to restrict emissions from the project to below the significance levels for PM and PM_{10}, thereby avoiding the requirements of the PSD program for PM and PM_{10}.

1.3.4.3. CO: Apparently, Ecology made an error when issuing PSD-00-02 Amendment 1. Conditions to limit CO emissions were removed from the PSD permit and placed into the NOC permit issued by NWCAA. Originally it was the goal of this amendment to return conditions that limit CO into the permit. On February 7, 2005, ConocoPhillips requested Ecology raise the emission limits of CO in the permit. Apparently, ConocoPhillips has had numerous problems complying with the emission limits in the original permit. Today's action will reinstate conditions to limit CO to the PSD permit. During a conference call on February 7, 2005, ConocoPhillips requested Ecology raise the CO emission limits because of difficulty they have had complying with the permitted limits. This information was e-mailed to Ecology on March 15, 2005. As of March 24, 2005, no comments on the proposed CO increase were received from the land managers.

The following paragraph prepared for the PSD-00-02 Amendment 3 TSD, was applicable to Amendment 3 and reflects the name of the facility at that time (ConocoPhillips Company) [Note: Amendment 3 was the last amendment to this permit (PSD-00-02) that was not an administrative change. Amendments 4–7 are administrative revisions]:

"At the time this application was determined to be "complete" (December 23, 2004) the State of Washington had two PSD programs. The federal program, delegated to the Washington State Department of Ecology (Ecology) by the Environmental Protection Agency (EPA) Region X on March 28, 2003 is based upon the March 3, 2003 version of 40 CFR 52.21. The states PSD program (which will be replaced by the new rules on February 10, 2005) is based upon the version of 40 CFR 52.21 that was in effect on July 1, 2000 version of 40 CFR 52.21. Both rules must be complied with for this permit. The federal rule allows a source to use the old rules (state method) for calculating emission increases. The state method is based on future potential emissions minus the past actual emissions. ConocoPhillips has elected to use the state method to evaluate emission increases for the purpose of this permit. What this means is that there is no additional analysis of emissions under the new federal rule required."

1.3.5. Amendment 4 (dated March 16, 2006) was an administrative amendment, extending the compliance date for Approval Condition 7 from December 31, 2006, until June 30, 2007. This compliance date was based upon an EPA Consent Decree. Phillips 66 (then ConocoPhillips) requested this amendment because they had difficulty scheduling the on-site construction of this project.

1.3.6. Amendment 5 (dated October 21, 2008) was an administrative amendment. Approval Condition 14 was changed from semi-annual to annual testing, and Approval Condition 21b was changed to submit testing reports within 30 days of the end of the month. ConocoPhillips (now Phillips 66) requested this amendment because they identified a discrepancy between this approval and the EPA Consent Decree.

1.3.7. Amendment 6 (dated August 23, 2011) was an administrative amendment that corrects a mistake in the wording that defines the flexibility of the time period between the annual tests required by existing Approval Conditions 13 and 14. The existing time period wording is incompatible with annual testing periods. There are no changes to the required testing interval or required test methods. ConocoPhillips (now Phillips 66) requested this change in a letter dated May 18, 2011, as a part of their Title V permit renewal process.

1.3.8. Amendment 7 (dated August 14, 2014) was an administrative amendment that accomplished the following three changes: it reflected the facility owner's name change from the ConocoPhillips Company to Phillips 66; expanded Condition 2 to include a consent decree short-term NO_X limit of 123.2 ppmvd at zero percent O_2 (7-day rolling average) for the Fluidized Catalytic Cracking Unit (FCCU) and carbon monoxide (CO) boiler; and also expanded Condition 2 to include a consent decree long-term NO_X limit of 96.1 ppmvd at zero percent O_2 (365-day rolling average) for the FCCU and CO boiler.

1.3.8.1. The facility name is now Phillips 66, which reflects the name change from the "ConocoPhillips Company" which occurred in 2012 after corporate restructuring. As described in the application for Amendment 7, "ConocoPhillips Refining & Marketing business and Exploration and Production business were separated into two stand-alone companies. Phillips 66 is now the owner and operator of the Ferndale Refinery." A "change of the owner or operator's business name and/or mailing address" is considered an "administrative revision" per Washington Administrative Code (WAC) 173-400-750(3)(a).

1.3.8.2. Based on Ecology's technical evaluation of the proposal, adding the following NO_X limits, "Does not reduce the stringency of the emission limitation in the PSD permit or the ability of ecology, the permitting authority, EPA, or the public to determine compliance with the approval conditions in the PSD permit." According to WAC) 173-400-750(3)(e), these changes are therefore considered an "administrative revision." The long- and short-term NO_X limits and requirements are based on the following June 3, 2014, EPA determination:[1]

[1] From. Phillip Brooks, Director Air Enforcement Division, EPA to: Tim Goedeker, Program Manager, US Consent Decrees, Phillips 66 Company Re· United States el al v. ConocoPhillips Co., NO H-05-258 (S D Tex) - Final FCCU NO_X Limits for the Phillips 66 Ferndale Refinery

1.3.8.3. The new long-term limit will be 96.1 ppmvd NO_X at zero percent O_2 on a 365-day rolling average basis to apply at all times (including during start-up, shutdown, and malfunction) that the FCCU and/or CO boiler are operating.

1.3.8.4. The new short-term limit will be 123.2 ppmvd NO_X at zero percent O_2 on a 7-day rolling average basis, and will exclude periods of start-up, shutdown, and malfunction, but will apply at all other times that the FCCU and/or CO boiler are operating.

1.4. PSD Applicability

- The Phillips 66, Ferndale Refinery, qualifies as a "major source" because it is included in the list of 28-named source categories and has the potential to emit more than 100 tpy of NO_X, CO, SO_2, and VOC.

1.5. New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP)

1.5.1. NSPS apply to certain types of equipment that are newly constructed, modified, or reconstructed after a given applicability date. The applicability of the following NSPS is presented in this section:

- NSPS Subpart Db (Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units)
- NSPS Subpart J (Standards of Performance for Petroleum Refineries)

While there are several other NSPS that apply to this facility, they are not triggered by this permit amendment.

1.5.2. NESHAP

- 40 CFR 63 Subpart UUU - Proposed (National Emission Standards for Petroleum Refineries -- Catalytic Cracking, Catalytic Reforming and Sulfur Plant Units)

Subpart UUU is not triggered by this permit amendment.

Although the current amendment is an administrative revision, PSD review details for previous permitting actions (both administrative and other) are included in the following sections to provide background information.

1.6. Emissions and Emissions Control

All emission increases above what the PSD program refers to as "significant" must undergo PSD review. When evaluating emissions against the PSD significance levels, a source's potential or allowable emissions are used. Potential emissions, or a source's Potential to Emit (PTE), are based on the theoretical operation 24 hours a day, 365 days per year (8,760 hours) or some other physical limitation of the equipment. In many cases, the number of hours a source would actually operate is lower than its potential emissions. If the source does not anticipate operation at its maximum capacity, it may request a federally enforceable limit on the hours of operation or some other measurable parameter. This limit, if placed in a federally enforceable permit, would result in "allowable" emissions as opposed to potential emissions.

The original application estimated the emissions and throughput of the facility. Originally, it was anticipated that nominal capacity of the FCCU would be 30,000 bpd. Since start-up of the FCCU in April 2003, Phillips 66 has determined that the unit can achieve an output of a nominal 35,000 bpd. An EPA Consent Decree addressed these issues and required Phillips 66 to obtain a PSD permit for PM and PM_{10} emissions.

1.6.1. Federally Enforceable Limitations

Several of the heaters are not able to reach their full capabilities due to undersized burners. Emissions from those units have been calculated below the units rated potential. The limitations are listed in Appendix A of the permit.

1.7. Netting Analysis

When a facility can show that emissions of a certain pollutant have actually reduced over time, it can use those reductions to "Net" out of PSD review. At the time the original permit was written, two methods of netting were required in Washington State. The federal method used a 5-year contemporaneous period. During the previous five years, all emission increases and decreases are summed and if the resultant is less than significance levels (40 tons for VOCs), that pollutant is not subject to PSD review. The state method utilized a 10-year contemporaneous period. The analysis is the same as the federal method, except for emission reductions older than one year the facility must apply "Emission Reduction Credits" to receive credit for those emissions.

Future potential emissions of VOCs were above the SERs (40 tpy) for this project. Phillips 66, however, applied emission reduction credits from June of 1993 for 1,443 tons of VOC and from April of 1992 for 196 tons of VOC. Phillips 66 also had a reduction in August of 1998 for 1,334.4 tons of VOC. Using the federal 5-year contemporaneous period, the net emission change for the last five years was a negative 1,043.90 tons. Using the 10-year Ecology method, the net emission change is a negative 1,371.90 tons. An evaluation of these methods results in this project not being subject to PSD requirements for VOC emissions.

1.8. Net Emissions Increases

Table 1 identifies the net emission increases associated with this project based upon Amendment 3.

Table 1. Net Emission Increases						
Emission Unit	Net Emission Increase (TPY)					
	PM	PM_{10}	SO_2	NO_x	VOC	CO
Crude Heater (1F-1)	084	0 84	(331 65)	30.81	0 61	9 24
Supplemental Crude Heater (1F-1A)	0 64	0 64	(142.82)	23 55	0 46	7 06
Liquid Feed Heater (4F-1A)	(1 42)	(1 42)	(0.06)	(8.20)	(1.03)	(15 71)
Tar Separator Heater (4-F-2)	1.23	1.23	(293.37)	45 38	0.89	13.62
Alky Depropanizer Reboiler (17F-1)	1 23	1.23	(118.86)	45.43	0.89	13 63
#2 HDF Heater – new LSD (14F-1,2,3)	1 23	1.23	(41 4)	16 75	0 89	13 63
DHT Heater (33F-1)	0 83	0.83	5 51	3 93	0.60	9 18
CGD Feed Heater (Model ID SRC19)	1.31	1.31	4.62	5 10	0.94	14 43
Sulfur Recovery Unit (SRU-19F-21)	0 56	0.56	2 66	5.72	0 43	6 84
#3 Reformer Preheat Heater (18F-1)	0.72	0.72	(0 28)	9 42	0 52	7 91
#3 Reformer Heaters (18F-21,22)	0 66	0 66	(13.08)	8 7	0 48	7 31
#3 Reformer Heaters (18F-23,24)	0 66	0.66	(13.08)	(8 7)	0.48	7.31
#3 Reformer Regen Heater (18F-26)	0 01	0.01	(5 15)	0.13	0.01	0 11
#1 Boiler (22F-1C)	3 71	3 71	(57 67)	25.44	2 68	41 01
Combustion Air Heater on FCC	N/A	N/A	N/A	N/A	0 005	N/A
FCC/COB Emissions (Model ID SRC21)	63 51	63.51	548 4	308 1	26.07	203 9
Old CO Boiler (4F-7)	(0.78)	(0.78)	(49 97)	(10 25)	(0 56)	(7 13)
TCC Surge Separator Vent (4D-3)	(64 8)	(45 4)	(920 5)	(19 1)	0	0
Storage Tanks	0	0	0	0	37 19	0
Product Loading	0	0	0	0	211 52	0
Equipment Fugitives	0	0	0	0	7 39	0
Project Emission Increase	10 14	29.54	(1426.69)	499 63	290.5	332 4
Creditable Decrease (EPA Method)	N/A	N/A	N/A	N/A	(1334 4)	N/A
Creditable Decrease (Ecology Method)	N/A	N/A	N/A	N/A	(1362 4)	N/A
Net Emissions Increase (EPA Method)	10 14	29 54	(1426 69)	499 63	(1043 90)	332 4
Net Emissions Increase (Ecology Method)	10.14	29.54	(1426.69)	499 63	(1371.90)	332 4

1.8.1. PM and PM_{10}

Historically, the state of Washington has measured particulate in the form of total suspended particulate. Total suspended particulate and particulate matter are interchangeable terms and for the remainder of this fact sheet, the term particulate matter will be used. PM_{10} is a subset of particulate matter and is composed of particles that are smaller than 10 microns in diameter.

EPA studies have shown PM_{10} to be a greater health risk than PM. PM_{10} and PM can cause a variety of environmental problems, including respiratory problems in humans and animals due to inhalation and deposition on plants and soil due to atmospheric fallout. Table 2 is a comparison of the net emissions increase from the original permit PM and PM_{10} emissions compared to Amendment 3's proposed emissions.

Table 2. PM/PM_{10} Emissions

Emission Unit	April 26, 2000 PM (TPY)	Nov. 18, 2004 PM (TPY)	Difference 2004-2000 PM (TPY)	April 26, 2000 PM_{10} (TPY)	Nov. 18, 2004 PM_{10} (TPY)	Difference 2004-2000 PM_{10} (TPY)
Crude Heater (1F-1)	0.8	0.8	—	0.8	0.8	—
Supplemental Crude Heater (1F-1A)	0.6	0.6	—	0.6	0.6	—
Liquid Feed Heater (4F-1A)	(1.4)	(1.4)	—	(1.4)	(1.4)	—
Tar Separator Heater (4-F-2)	1.2	1.2	—	1.2	1.2	—
Alky Depropanizer Reboiler (17F-1)	1.2	1.2	—	1.2	1.2	—
#2 HDF Heater – new LSD (14F-1,2,3)	1.2	1.2	—	1.2	1.2	—
DHT Heater (33F-1)	0.8	0.8	—	0.8	0.8	—
HCG HDS Feed Heater[1]	1.3	—	(1.3)	1.3	—	(1.3)
HCC HDS Stripper Reboiler[1]	1.1	—	(1.1)	1.1	—	(1.1)
CGD Feed Heater (Model ID SRC19)[1]	—	1.3	1.3	—	1.3	1.3
Sulfur Recovery Unit (SRU-19F-21)	0.6	0.6	—	0.6	0.6	—
#3 Reformer Preheat Heater (18F-1)	0.7	0.7	—	0.7	0.7	—
#3 Reformer Heaters (18F-21,22)	0.7	0.7	—	0.7	0.7	—
#3 Reformer Heaters (18F-23,24)	0.7	0.7	—	0.7	0.7	—
#3 Reformer Regen Heater (18F-26)	0.01	0.01	—	0.01	0.01	—
#1 Boiler (22F-1C)	3.7	3.7	—	3.7	3.7	—
Combustion Air Heater on FCC[2]	—	—	—	N/A	—	—
FCC Emissions[2]	75.1	—	(75.1)	46.9	—	(46.9)
New CO Boiler Aux fuel fireing[2]	—	—	—	N/A	—	—
FCC/COB Emissions (Model ID SRC21)[2]	—	63.5	63.5	—	63.5	63.5
Old CO Boiler (4F-7)	(0.8)	(0.8)	—	(0.8)	(0.8)	—
TCC Surge Separator Vent (4D-3)	(64.8)	(64.8)	—	(45.4)	(45.4)	—
Storage Tanks	0	0		0	0	—
Product Loading	0	0		0	0	—
Equipment Fugitives	0	0		0	0	—
Project Emission Increase	22.7	10.0	(12.7)	13.91	29.4	15.5

[1] PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater.

[2] This is actually the same equipment accounted for differently

Total projected emissions of PM are 10 tpy. Amendment 3 results in a 12.7 tpy decrease over the original permitted limits PM. EPA and the NWCAA requested Ecology include a PM limit in Amendment 3. While PM is not technically subject to PSD review, an enforceable limit will be placed in the permit.

Total projected emissions of PM_{10} are 29.54 tpy. Amendment 3 resulted in a 15.52 tpy increase over the original PM_{10} permitted limits.

1.8.2. Sulfur Oxides

During the combustion of fossil fuels, sulfur contained in the fuel is released into the atmosphere as sulfur oxides. This sulfur is converted into compounds that are responsible, in part, for acid rain. The air can absorb some sulfur without causing a measurable increase in the sulfur in the air. Nevertheless, regulatory agencies are required to keep these emissions below thresholds that cause harm to the environment and to human health. Table 3 is a comparison of the net emissions increase from the original permit SO_X emissions compared to Amendment 3.

Table 3. SO_X Emissions

Emission Unit	April 26, 2000 SO_X (TPY)	Nov. 18, 2004 SO_X (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	(331 6)	(331 6)	—
Supplemental Crude Heater (1F-1A)	(142.8)	(142 8)	—
Liquid Feed Heater (4F-1A)	(0 06)	(0 06)	—
Tar Separator Heater (4-F-2)	(293.3)	(293 3)	—
Alky Depropanizer Reboiler (17F-1)	(118 8)	(118 8)	—
#2 HDF Heater – new LSD (14F-1,2,3)	(41 4)	(41 4)	—
DHT Heater (33F-1)	5 5	5.5	—
HCG HDS Feed Heater[1]	4 6	—	(4 6)
HCC HDS Stripper Reboiler[1]	4.0	—	(4.0)
CGD Feed Heater (Model ID SRC19)[1]	—	4.6	4 6
Sulfur Recovery Unit (SRU-19F-21)	2 7	2 7	—
#3 Reformer Preheat Heater (18F-1)	(0 3)	(0 3)	—
#3 Reformer Heaters (18F-21,22)	(13.1)	(13.1)	—
#3 Reformer Heaters (18F-23,24)	(13.1)	(13.1)	—
#3 Reformer Regen Heater (18F-26)	(5 1)	(5.1)	—
#1 Boiler (22F-1C)	(57 7)	(57 7)	—
Combustion Air Heater on FCC[2]	0 2	N/A	(0 2)
FCC Emissions[2]	547 7	—	(547.7)
New CO Boiler Aux fuel fireing[2]	0 8	—	(0 8)

Table 3. SOx Emissions			
Emission Unit	April 26, 2000 SOx (TPY)	Nov. 18, 2004 SOx (TPY)	Difference 2004-2000 (TPY)
FCC/COB Emissions (Model ID SRC21)[2]	---	548 4	548 4
Old CO Boiler (4F-7)	(50)	(50)	—
TCC Surge Separator Vent (4D-3)	(920 5)	(920.5)	—
Storage Tanks	0	0	---
Product Loading	0	0	—
Equipment Fugitives	0	0	—
Project Emission Increase	(1422.26)	(1426 69)	(4.4)

[1] PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater

[2] This is actually the same equipment accounted for differently

The emission units that will have a change in SO_X are shown in Table 3. Emissions of SO_X (-1426.69 tpy) are lower than the PSD SER (40 tpy) and the change between the original permit and Amendment 3 is a 4.4 tpy reduction in SO_X emissions. Therefore, SO_X was not subject to PSD review in Amendment 3.

1.8.3. Nitrogen Oxides

During the combustion of fossil fuels, nitrogen oxides are released into the atmosphere. This nitrogen, in the form of NO_X, is converted into compounds that are partly responsible for smog. Even though air, made up of approximately 79 percent nitrogen, the remainder being oxygen and trace amounts of other compounds, can absorb some additional nitrogen oxides without causing a measurable increase in smog. Sources that emit NO_X are required to keep these emissions below thresholds that cause harm to the environment and human health.

NO_X emissions are normally generated by the oxidation of nitrogen in the fuel (fuel-bound nitrogen) or nitrogen in the combustion air (thermal NO_X). Table 4 is a comparison of the net emissions increase from the original permit NO_X emissions compared to Amendment 3 emissions.

Table 4. NOx Emissions			
Emission Unit	April 26, 2000 NOx (TPY)	Nov. 18, 2004 NOx (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	30 8	30 8	---
Supplemental Crude Heater (1F-1A)	23 5	23 5	—

Table 4. NOx Emissions			
Emission Unit	April 26, 2000 NOx (TPY)	Nov. 18, 2004 NOx (TPY)	Difference 2004-2000 (TPY)
Liquid Feed Heater (4F-1A)	(8.2)	(8.2)	---
Tar Separator Heater (4-F-2)	45.4	45.4	—
Alky Depropanizer Reboiler (17F-1)	45.4	45.4	---
#2 HDF Heater – new LSD (14F-1,2,3)	16.7	16.7	—
DHT Heater (33F-1)	3.9	3.9	---
HCG HDS Feed Heater[1]	7.0	—	(7.0)
HCC HDS Stripper Reboiler[1]	6.1	—	(6.1)
CGD Feed Heater (Model ID SRC19)[1]	—	5.1	5.1
Sulfur Recovery Unit (SRU-19F-21)	5.7	5.7	—
#3 Reformer Preheat Heater (18F-1)	9.4	9.4	—
#3 Reformer Heaters (18F-21,22)	8.7	8.7	—
#3 Reformer Heaters (18F-23,24)	8.7	8.7	—
#3 Reformer Regen Heater (18F-26)	0.1	0.1	—
#1 Boiler (22F-1C)	25.4	25.4	—
Combustion Air Heater on FCC[2]	0.8	---	(0.8)
FCC Emissions[2]	463.1	—	(463.1)
New CO Boiler Aux fuel firing[2]	30.2	—	(30.2)
FCC/COB Emissions (Model ID SRC21)[2]	—	308.1	308.1
Old CO Boiler (4F-7)	(10.2)	(10.25)	—
TCC Surge Separator Vent (4D-3)	(19.1)	(19.1)	—
Storage Tanks	0	0	—
Product Loading	0	0	—
Equipment Fugitives	0	0	—
Project Emission Increase	693.4	499.63	(193.8)

[1] PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater

[2] This is actually the same equipment accounted for differently

The emission units that will have a change in NOx are shown in Table 4. Emissions of NOx (499.63 tpy) are higher than the PSD SER (40 tpy) but less than those in the original permit (693.4 tpy). There were no proposed changes in the permit limits for NOx in Amendment 3.

1.8.4. VOCs

VOCs have the potential to cause or contribute to ozone levels that violate the national ambient air quality standards for ozone. Ozone is a major component of smog which causes adverse health and environmental impacts when present in sufficiently high concentrations at ground level. Table 5 is a comparison of the net emissions increase from the original permit VOC emissions to Amendment 3 emissions.

Table 5. VOC Emissions

Emission Unit	April 26, 2000 VOC (TPY)	Nov. 18, 2004 VOC (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	0 6	0 61	—
Supplemental Crude Heater (1F-1A)	0.5	0 5	—
Liquid Feed Heater (4F-1A)	(1.0)	(1 0)	—
Tar Separator Heater (4-F-2)	0 9	0 9	—
Alky Depropanizer Reboiler (17F-1)	0.9	0.89	—
#2 HDF Heater – new LSD (14F-1,2,3)	0.9	0 89	—
DHT Heater (33F-1)	0 6	0 6	—
HCG HDS Feed Heater[1]	0 9		(0 9)
HCC HDS Stripper Reboiler[1]	0 8		(0.8)
CGD Feed Heater (Model ID SRC19)[1]	—	0 9	0 9
Sulfur Recovery Unit (SRU-19F-21)	0 4	0 4	—
#3 Reformer Preheat Heater (18F-1)	0.5	0 5	—
#3 Reformer Heaters (18F-21,22)	0.5	0 5	—
#3 Reformer Heaters (18F-23,24)	0 5	0 5	—
#3 Reformer Regen Heater (18F-26)	0.01	0.01	—
#1 Boiler (22F-1C)	2 7	2 7	—
Combustion Air Heater on FCC[2]	0 05	0 05	—
FCC Emissions[2]	20.1	—	(20.1)
New CO Boiler Aux fuel fireing[2]	1.6	—	(1 6)
FCC/COB Emissions (Model ID SRC21)[2]	—	26 1	26 1
Old CO Boiler (4F-7)	(0 6)	(0 6)	—
TCC Surge Separator Vent (4D-3)	0	0	—
Storage Tanks	21.8	37 2	15 4
Product Loading	124 2	211 5	87.3
Equipment Fugitives	7.4	7 4	—
Project Emission Increase	184.3	290 5	106 3
Net Emissions Increase (EPA Method)	**(1,150.1)**	**(1,043.9)**	
Net Emissions Increase (Ecology Method)	**(1178.1)**	**(1,071.9)**	

[1] PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater

[2] This is actually the same equipment accounted for differently

The emission units with VOC emission changes resulting from Amendment 3 are shown in Table 6. Emissions of VOCs (290.5 tpy) are higher than the PSD SER (40 tpy). However, looking back to the netting analysis performed in 2000, the project resulted in greater than 1,000 tons of VOC credits being unused. This reduction greatly improved the air quality in the vicinity of the Ferndale Refinery. Had it not been for the error made by Phillips 66 of underestimating the throughput capacity of the FCCU, VOC emissions would not be discussed here. Ecology has determined that since Amendment 3 was a correction to a permit that had already been issued, it was appropriate to look back at the original netting analysis and calculate the increase in VOC emissions based upon the April 2000 numbers. VOCs were therefore not subject to PSD review in Amendment 3.

1.8.5. CO

CO is a colorless, odorless, and at high levels, a poisonous gas, formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 60 percent of all CO emissions nationwide. High concentrations of CO generally occur in areas with heavy traffic congestion. In cities, as much as 95 percent of all CO emissions may come from automobile exhaust. Other sources of CO emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. Peak CO concentrations typically occur during the colder months of the year when CO automotive emissions are greater and nighttime inversion conditions (where air pollutants are trapped near the ground beneath a layer of warm air) are more frequent. CO enters the bloodstream through the lungs, and reduces oxygen delivery to the body's organs and tissues. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all effects associated with exposure to elevated CO levels.

Table 6 is a comparison of the net emissions increase from the original permit CO emissions compared to Amendment 3 emissions.

Table 6: CO Emissions

Emission Unit	April 26, 2000 CO (TPY)	Nov. 18, 2004 CO (TPY)	Difference 2004-2000 (TPY)
Crude Heater (1F-1)	9 2	9 2	—
Supplemental Crude Heater (1F-1A)	7 1	7 1	—
Liquid Feed Heater (4F-1A)	(15 7)	(15.7)	—
Tar Separator Heater (4-F-2)	13 6	13 6	—
Alky Depropanizer Reboiler (17F-1)	13 6	13 6	—
#2 HDF Heater – new LSD (14F-1,2,3)	13 6	13 6	—
DHT Heater (33F-1)	9.2	9 2	—
HCG HDS Feed Heater[1]	14.4	—	(14 4)
HCC HDS Stripper Reboiler[1]	12 6	—	(12 6)

Table 6. CO Emissions

Emission Unit	April 26, 2000 CO (TPY)	Nov. 18, 2004 CO (TPY)	Difference 2004-2000 (TPY)
CGD Feed Heater (Model ID SRC19)[1]	—	14.4	14.4
Sulfur Recovery Unit (SRU-19F-21)	6.8	6.8	—
#3 Reformer Preheat Heater (18F-1)	7.9	7.9	—
#3 Reformer Heaters (18F-21,22)	7.3	7.3	---
#3 Reformer Heaters (18F-23,24)	7.3	7.3	---
#3 Reformer Regen Heater (18F-26)	0.1	0.1	—
#1 Boiler (22F-1C)	41.0	41.0	—
Combustion Air Heater on FCC[2]	0.7	N/A	(0.7)
FCC Emissions[2]	42.3	—	(42.3)
New CO Boiler Aux fuel fireing[2]	24.9	—	(24.9)
FCC/COB Emissions (Model ID SRC21)[2]	—	203.9	203.9
Old CO Boiler (4F-7)	(7.1)	(7.1)	---
TCC Surge Separator Vent (4D-3)	(0)	0	—
Storage Tanks	0	0	—
Product Loading	0	0	—
Equipment Fugitives	0	0	—
Project Emission Increase	209.0	332.4	123.4

[1] PSD-00-02 Amendment 1 allowed for the replacement of the HCG feed heater and stripper reboiler with the CGD feed heater

[2] This is actually the same equipment accounted for differently

The emission units that had an increase in CO (for Amendment 3) are shown in Table 6. The emissions increase of CO (332.4 tpy) is greater than the PSD SER (100 tpy) and the original permit (209.0 tpy). As per Consent Decree, ConocoPhillips will comply with revised emissions limits for CO.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1. Definitions

Best Available Control Technology (BACT) is defined as an emission limitation based on the most stringent level of emission control applied at a similar source that is technically and economically feasible.

In a BACT analysis, the applicant must rank all control options from highest level of control to the lowest. If the applicant can show that the highest level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is evaluated. Ultimately, the burden of proof is on the applicant to prove why the most stringent level of control should not be used.

2.2. Regulatory Requirements

An applicant is required by federal law to use BACT for any pollutant that will have a significant emission increase at any PSD source. An applicant is required by Washington State regulations to use BACT for any pollutant that will have increased emissions, provided that the emission unit was physically modified.

If a project is proposed in an area that exceeds ambient air quality standards for a pollutant, the proposed source must use a control technology that will result in the lowest achievable emission rate (LAER) for that pollutant. Additionally, the applicant would be required to reduce emissions from other sources in the area at least as much as the proposed source will increase emissions. However, the site of the Amendment 3 modification is in an area which has been designated as in attainment with national and state ambient air quality standards for PM/PM_{10}, NO_X, CO, and VOC. Therefore, the facility is not required to install LAER.

2.3. Clearinghouse Control Technology Review

There was no new clearinghouse review performed for PM_{10} emissions. After a quick review of the clearinghouse, Ecology believes that the review performed for the original PSD application (April 4, 2001) is sufficient to satisfy the requirements for clearinghouse review. For CO emissions, Phillips 66 submitted information shown in Table 7. (The following BACT section was performed for Amendment 3 but is included in this updated TSD to provide background information.)

Table 7. CO Clearinghouse Results

Permit Date	RBLC ID	Facility Name	Process Name	Short-Term Limit (ppmdv @ 0% O_2)	Long-Term Limit (ppmdv @ 0% O_2)	Control Method
4/3/2002	TN-0153	Williams Refining & Marketing, LLC	FCCU	300	50	(N)
8/18/2004	OK-0102	Ponca City Refinery	FCCU, (2)	500	150	(FCCU-CO COMBUSTION PROMOTER)
6/10/2002	TX-0379	ExxonMobil Beaumont Refinery	FCCU CO BOILER STACK (PRESCRUBBER)	500	N/A	(N) NONE INDICATED
6/10/2002	TX-0379	ExxonMobil Beaumont Refinery	FCCU SCRUBBER STACK	500	500	(N) NONE INDICATED

Table 7. CO Clearinghouse Results

Permit Date	RBLC ID	Facility Name	Process Name	Short-Term Limit (ppmdv @ 0% O_2)	Long-Term Limit (ppmdv @ 0% O_2)	Control Method
10/5/2001	TX-0346	West Refinery	(FCCU)	500	500	(B) MIX WITH NAT GAS AND INCINERATE IN CO BOILER
5/23/2001	TX-0359	Limestone Electric Generating Station	FLUIDIZED-BED CATALYTIC CRACKING UNIT (FCCU)	500	100	(P) USE OF FULL COMBUSTION
2/23/2000	TX-0429	Valero Refining Co – Texas City	FCCU	500	500	(A) CO BOILER
5/11/2001	AR-0061	Lion Oil Co Refinery, El Dorado	FLUIDIZED-BED CATALYTIC CRACKING UNIT (FCCU)	500	100	(P) USE OF FULL COMBUSTION
12/14/1990	VI-0003	Hess Oil Virgin Island Corp. – Hovic	FCC UNITS, 2	649 6	432	(P) COMBUSTION CONTROL & HIGH TEMP REGENERATOR
1/13/2003	OK-0092	Valero Ardmore Refinery	FCCU Regenerator No 1	N/A	N/A	(P) CO BOILER AND INCINERATOR
1/13/2003	OK-0092	Valero Ardmore Refinery	FCCU REGENERATOR NO 2	N/A	N/A	(P) HIGH TEMPERATURE REGENERATION
2/10/1995	LA-0090	TransAmerican Refining Corp	REGENERATOR, FCCU	N/A	N/A	(B) CO BOILER OR HIGH TEMP REGENERATION
1/15/1993	LA-0085	TransAmerican Refining Corp.	REGENERATOR, FCCU (NO 1)	N/A	N/A	(A) CO BOILER
1/15/1993	LA-0085	TransAmerican Refining Corp.	CATALYTIC CRACKING FCCU REGENERATOR	N/A	N/A	(A) CO BOILER
6/14/1991	LA-0078	Murphy Oil USA, Inc	FCCU (FLUID CATALYTIC CRACKING UNIT)	N/A	N/A	(A) HIGH TEMP REGENERATOR AT >1300 DEGREES F
6/9/2003	OK-0089	TPI Petroleum Inc , Valero Ardmore Refinery	REGENERATOR & THERMAL OXIDATION SYSTEM, FCCU NO 1	N/A	N/A	(A) CO BOILER AND INCINERATOR
6/9/2003	OK-0089	TPI Petroleum Inc , Valero Ardmore Refinery	REGENERATOR, FCCU NO. 2	N/A	N/A	(P) HIGH TEMPERATURE REGENERATION

2.4. BACT for PM and PM_{10}

The following technologies were considered for controlling PM/PM_{10} emissions from the FCCU in the April 20, 2000, permit application as shown in Table 8.

Table 8. BACT Analysis for PM_{10}			
Technology	**Effectiveness**	**Technically Feasible?**	**Selected as BACT?**
Baghouse	>99%	No	No
Electrostatic Precipitator	0 10 lb/1,000 lb Coke Burned	Yes	No
Wet Gas Scrubber	**0.50 lb/1,000 lb Coke Burned[1]**	**Yes**	**Yes**
Cyclone	< 30%	Yes	No
[1] As per Consent Decree, 0 8 lb/1,000 lb will be the emission standard between January 27, 2005, and the date that COPC demonstrates compliance with the 0 50 lb/1000 lb coke burned, but no later than June 30, 2007			

2.4.1. Baghouse

Baghouses cannot operate in moist environments due to filter binding. The regenerator flue gas leaves the heat recovery unit between 600° and 750°F. The maximum operating temperature for economical, commercially available filter media is 500°F. Baghouse operating temperatures in excess of filter maximum operating temperatures create the potential for explosion or fire. For these reasons, the applicant proposed that the baghouse was technically infeasible for controlling PM/PM_{10} emissions from the FCC regenerator. Ecology agrees that a baghouse would be technically infeasible.

2.4.2. Electrostatic Precipitator

Electrostatic Precipitators (ESPs) have long been used for the control of PM/PM_{10} from FCC regenerator effluents An ESP designed to achieve 95 percent PM/PM_{10} control was evaluated for BACT. The applicant stated that the cost associated with this technology was excessive. Those cost numbers were not available to the author of this document at the time this document was prepared. However, because the wet gas scrubber is already in place and the increase in PM/PM_{10} emissions associated with this modification is only 29 tpy, Ecology agrees that an electrostatic precipitator for controlling PM/PM_{10} emissions is not BACT for this project.

2.4.3. Wet Gas Scrubber

A wet gas scrubber was proposed by the applicant for controlling SO_2 emissions. It is also the next technology with the next highest removal efficiency in the top down evaluation for PM/PM_{10} control. It is capable of achieving 0.8 lb PM/PM_{10} per 1,000 lb coke burn off and 0.50 lb PM/PM_{10} per 1,000 lb of coke burned. The applicant estimated the cost per ton of PM/PM_{10}

remove to be $13,402. While this figure generally exceeds the cost threshold Ecology used for economic viability, Ecology agrees that a wet gas scrubber satisfies BACT for the control of PM/PM_{10} emissions from the FCC regenerator.

2.4.4. Cyclones

Cyclones have the lowest control efficiency of all of the identified technologies. As particle size decreases, so does efficiency. Cyclones have difficulty removing particles of 30 microns or smaller. Cyclones are already employed to separate the catalyst from the gas stream prior to the wet gas scrubber. Particulate emissions from a wet gas scrubber typically have a particle diameter of less than 10 microns. The applicant determined the use of cyclones to be technically infeasible for controlling emissions of PM/PM_{10} from the FCC regenerator.

While Ecology does not agree that cyclones are technically infeasible, we do agree that the removal efficiency would be extremely low and therefore the wet gas scrubber was selected as BACT above.

2.5. BACT for CO

The following technologies were considered for controlling CO emissions from the FCCU in the April 20, 2000, permit application as shown in Table 9.

Table 9. BACT Analysis for CO

Technology	Effectiveness	Technically Feasible?	Selected as BACT?
High temperature regeneration	50–500 ppm	No	No
Thermal oxidation	**50–500 ppm**	**Yes**	**Yes**
Catalytic oxidation	50–500 ppm	No	No
CO combustion promoter	500 ppm	Yes	No

2.5.1. High Temperature Regeneration

High temperature regeneration or full combustion regeneration uses excess oxygen and high operating temperatures, 1,300° to 1,400°F, to reduce carbon deposits, or coke, on FCC catalyst and to complete the conversion of CO to carbon dioxide (CO_2). This operating method is sometimes used in conjunction with CO combustion promoter. Phillips 66 FCC can operate at both full and partial combustion scenarios. In partial combustion mode, the regenerator does not continuously supply fuel and excess oxygen. It would therefore be impossible to achieve the high operating temperature of the full combustion mode to reduce carbon deposits on the FCC catalyst and complete the combustion of CO to CO_2 when operating in the partial combustion mode Phillips 66 has determined that the use of high temperature regeneration to control the emissions of CO from the FCC is technically infeasible because it would only work part of the time. Ecology agrees that high temperature regeneration for controlling CO emissions from the FCC is technically infeasible and is not evaluated further.

2.5.2. Thermal Oxidation

Thermal oxidation uses the concepts of temperature, time, and turbulence to achieve complete combustion. The combustion process is thought of as occurring in two separate stages: (1) the combustion of fuels and (2) the combustion of pollutants. Use of a thermal oxidizer is equivalent to adding a combustion chamber where the regenerator vent gas is heated above its ignition temperature. Excess oxygen and additional fuel are supplied to reach this higher temperature and complete the conversion of CO to CO_2.

The most common type of thermal oxidizer currently used to control CO emissions from a partial burn FCC regenerator is a CO boiler. CO boilers typically operate at approximately 1,800°F to ensure complete conversion. Phillips 66 currently operates a CO boiler as part of the existing FCC system.

Partial burn FCC regenerators operate at or below 1,250°F. The lower operating temperatures result in regenerator vent gas CO concentrations well in excess of 500 ppmdv. Once the vent gases pass through a CO boiler, CO concentrations are between 50 and 500 ppmdv, comparable to high temperature regeneration FCC effluents. For refiners operating high temperature regeneration FCCs, a CO boiler is not necessary because effluent CO concentrations are already less than 500 ppmdv.

The FCC at the Ferndale Refinery will be designed to operate under both full and partial combustion scenarios. Refineries that operate partial combustion FCCs use CO boilers to control CO emissions. Refineries operating FCCs exclusively in a full combustion mode, also known as high temperature regeneration, do not require the use of a CO boiler. Partial combustion regeneration followed by a CO boiler achieves comparable results to high temperature regeneration. CO boilers are typically used to control regenerator effluents with CO concentrations in excess of 1,000 ppmdv. Therefore, a CO boiler is necessary to control CO emissions from this process. The RBLC database has identified CO Boilers as BACT for partial combustion FCCs.

Phillips 66 proposed thermal oxidation to be BACT for controlling CO emissions from the FCC. Ecology agrees that the use of a CO boiler is BACT for controlling CO emissions from the FCC.

2.5.3. Catalytic Oxidation

Catalytic oxidizers are an alternative to thermal oxidizers. A solid catalyst is used to create a heterogeneous reaction. A catalyst is an element or compound that speeds up a reaction without undergoing change itself. The catalyst allows complete oxidation to take place at a faster rate and at a lower temperature than is capable by thermal oxidation.

In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at 650°F to 1,000°F. Approximately 1.5 to 2.0 ft^3 of catalyst is required per 1,000 standard ft^3 per minute gas flow rate (waste gas plus supplementary fuel combustion products).

The main problem in catalytic oxidizers is the loss of catalyst activity. They cannot be used on waste gas streams containing significant amounts of particulate matter. Particulate deposits foul the catalyst and prohibit oxidation. High temperatures also accelerate catalyst deactivation. Even short-term temperatures above 1,500°F can cause almost total loss of catalyst activity.

Phillips 66 has proposed that the use of catalytic oxidation to control the emissions of CO from the FCC is technically infeasible. Ecology agrees that catalytic oxidation for controlling CO emissions from the FCC is technically infeasible and is not evaluated further.

2.5.4. CO Combustion Promoter

Complete oxidation of CO to CO_2 takes place in an ideally designed and operated regenerator. However, since ideal conditions cannot always be reached and maintained during industrial operation, some petroleum refiners use a CO combustion promoter. The promoter is a platinum and/or palladium catalyst that is injected into full combustion regenerators only as needed to ensure that CO concentrations remain below 500 ppmdv.

While use of a CO combustion promoter can lower the CO content of the flue gas, it also has some drawbacks. Promoter is frequently added to the regenerator two to three times per day at a rate of 3 to 5 pounds per ton (lb/ton) of fresh FCC catalyst. The promoter increases the requirement for combustion air and raises the regenerator temperature thus, increasing thermal deactivation of the catalyst. It is also important to verify the metallurgy in the regenerator is designed to accommodate higher temperature operation.

Catalytic oxidation is able to achieve a greater reduction in CO emissions. Therefore, the CO combustion promoter is not considered further.

3. AMBIENT AIR QUALITY ANALYSIS

3.1. Impact Assessment

This section addresses changes from Amendment 3 only (Amendments 4–8 are administrative revisions that that do not alter the results of this section).

PSD rules require an assessment of ambient air quality impacts from any new or modified major facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to the maximum allowable increments prevents significant deterioration of air quality.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (NAAQS) analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed project result in impacts greater than the modeling significance levels (MSLs). Then, for those pollutants and averaging periods that have impacts greater than the MSL, a NAAQS analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. The PSD Increment analysis is used to determine if the change in the air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

This section will discuss the air quality impact analysis of the nearby Class II area. The air quality impact analysis for the Class I areas will be discussed along with the Air Quality Related Values (AQRVs) in Chapter 4.

Table 10 is a comparison of the proposed projects maximum-modeled pollutant concentrations, to the PSD programs Class II modeling Significant Impact Levels (SILs) and monitoring de minimis levels. If the maximum projects modeled emissions exceed the de minimis levels additional preconstruction ambient monitoring may be required.

Table 10. Comparison of the Maximum Modeled Pollutant Concentrations to the SILs and de Minimis Levels

Pollutant	Averaging Period	Monitoring de Minimis Level (µg/m³)	Modeling SIL (µg/m³)	Maximum Concentration (µg/m³)
PM_{10}	Annual	—	1	0.50
	24-hour	10	5	3 74
CO	1-hour	—	2,000	845 35
	8-hour	575	500	447 30

The predicted ambient impacts from emissions of PM_{10} and CO do not exceed the monitoring de minimis levels. Ecology has determined that this data is adequate to determine that no preconstruction monitoring will be required as shown in Table 10.

Emissions of PM_{10} and CO are also below the modeling SILs. Therefore, further modeling for cumulative impact and increment analyses is not required.

3.2. Toxic Air Pollutants

There is no toxic pollutant increases associated with this project. An analysis of toxic air pollutants was performed by NWCAA.

4. AQRVs

This section addresses changes from Amendment 3 only (Amendments 4–8 are administrative revisions that that do not alter the results of this section).

CO is not a Class I pollutant of concern because CO does not impact visibility or deposition and an increment analysis is not required. Therefore, the remainder of this section addresses emissions of PM_{10}.

In order to show that the increase in PM_{10} emissions did not impact a Class I area, an ISC-PRIME model was run for the nearest Class I area (North Cascade National Park). Table 11 compares the modeling results with the Class I MSLs for PSD increment. The concentration shown represents the highest modeled concentration.

Table 11. Comparison of the Maximum Modeled Pollutant Concentrations to the Class I Area SILs

Pollutant	Averaging Period	Modeling Results (ug/m³)	Class I Area SILs EPA Proposed (ug/m³)	Class I Area SILs FLM Recommended (ug/m³)	PSD Class I Area Increment (ug/m³)
PM_{10}	24-hour	0 0352	0.3	0 27	8
	Annual	0 0028	0 2	0 08	4

4.1. Impacts on Visibility

Because the maximum PM_{10} concentrations are below the proposed EPA and FLM Class I area SILs, no further modeling is required. The project was not expected to cause a significant impact to the air in the Class I area as shown in Table 11.

Since Amendment 3 addressed only an increase in PM_{10} emissions which are minor (<30 tons per year) and the impacts analysis were below the recommended SILs, no visibility impact was required.

4.2. Other AQRVs

No deposition analysis was required for Amendment 3 because that application only addressed an increase in PM_{10} emissions.

4.3. Construction and Growth Impacts

The proposed modification will not involve any new construction activities. Nor will it lead to an increase in the number of employees at the Ferndale Refinery. Therefore, no increase in emissions from residential growth or in commuting-related mobile source emissions will be directly related to the proposed project. Therefore, the proposed project is not expected to cause adverse construction and growth-related impacts.

4.4. IMPACTS ON VEGETATION

The proposed project is not expected to have a significant impact on soils and vegetation from the proposed changes at the Ferndale Refinery.

5. CONCLUSION

The project will have no significant adverse impact on air quality. The Washington State Department of Ecology finds that the applicant, Phillips 66, has satisfied all requirements for PSD.

For additional information, please contact:

Robert C. Burmark, P.E.
Washington State Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600
(360) 407-6812
robert.burmark@ecy.wa.gov

Enclosure 4

Ecology's November 27, 2019 Information Request

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

November 27, 2019

Phillips 66
3901 Unick RD
Ferndale, WA 98248-9003

Re: Regional Haze 4-Factor Analysis

Dear Erin Strang:

As we noted in our May 31, 2019 letter, the Washington State Department of Ecology (Ecology) determined that a 4-Factor/RACT (Reasonably Available Control Technology) analysis is required for refineries, including your facility. Ecology determined this after meeting with the Western States Petroleum Association (WSPA) and their representatives. Tery Lizarraga (WSPA) communicated to Ecology in a November 12, 2019 email that the refineries were expecting to receive letters from Ecology outlining Ecology's information requests and timelines going forward. This letter details that information request.

Ecology is requesting:

- All records and data from previous retrofits since 1996 for each operational fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr, and heater greater than 40 MMBtu/hr located at your facility. Please provide this information as soon as possible, but no later than **January 31, 2020.**
- 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 your facility that has not been retrofitted since 2005. Please provide this information as soon as possible, but no later than **March 31, 2020**, with a progress report on **January 31, 2020**. The progress report should include what tasks have been completed in the 4-Factor analysis and what tasks are remaining.

The goal of the Regional Haze Rule is to reduce pollutants associated with regional haze: particulate matter (PM10), sulfur dioxide (SO2), nitrogen oxides (NOx), sulfuric acid (H2S04), and ammonia (NH3). To meet requirements of this rule, for each unit type listed above, Ecology requests the following in support of the 4-Factor analysis:

- The cost of compliance for each identified control, equipment update, or operational practice if lower emission limits are implemented via additional controls, updated equipment, or other operational improvements.

- The time necessary for compliance.
- The energy and non-air quality environmental impacts of compliance (e.g., non-air waste streams).
- The remaining useful life of any existing source subject to such requirements.

Please include all information regarding activities that have the potential to reduce the cost of compliance. This includes, but is not limited to:

- Projects that can reduce the heat load to the heaters (air preheater, liquid to liquid heat exchangers, etc.)
- Performing work during regularly scheduled maintenance cycles.

Note that all supporting information and assumptions used in the 4-Factor analysis need to be identified, listed, and provided to Ecology.

Additional resources are listed below:

- The current EPA Control Cost Manual (https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution).

- Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. August 2019. Publication: EPA-457/B-19-003. (https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period). This document provides specific instructions for the 4-Factor components being requested by Ecology.

- Ecology's February 2010 Tesoro BART review https://fortress.wa.gov/ecy/publications/parts/1002041part1.pdf. Appendix L, page L-102 (page 1243 of 1706). This review found various heaters and FCCU that were cost effective for control.

During a previous meeting between Ecology, WSPA, and the refineries, we discussed both 4-Factor analysis and RACT analysis. This letter requests information needed for the 4-Factor analysis. We will provide further instructions by the end of December. If you have additional questions, please contact Philip Gent Philip.gent@ecy.wa.gov or call (360) 407-6810.

Sincerely,

Chris Hanlon-Meyer
Science and Engineering Section Manager
Air Quality Program

cc: Philip Gent, Ecology

Enclosure 5

Email regarding emissions reductions in the previous planning period entitled “RE Phillips 66 Regional Haze Information Request”

Strang, Erin T

From:	Inloes, Scott (ECY) <SINL461@ECY.WA.GOV>
Sent:	Thursday, June 6, 2019 9:07 AM
To:	Strang, Erin T; TobyM@nwcleanairwa.gov
Cc:	Paris, Sandy; RSC:Ferndale Records
Subject:	[EXTERNAL]RE: Phillips 66 Regional Haze Information Request

Erin,

Thanks for the information and the onsite visit. So far I don't have any questions. This information was very help full at understanding the environmental beneficial projects that have been done at Phillips 66.

Ecology has not set a date for the regional haze public meetings Ecology will notify you the date of any Regional Haze meetings.

Scott Inloes, PE.
Air Quality Program
WA Department of Ecology
Phone: 360-407-6896

From: Strang, Erin T [mailto:Erin.T.Strang@p66.com]
Sent: Wednesday, June 05, 2019 11:05 AM
To: Inloes, Scott (ECY) <SINL461@ECY.WA.GOV>; TobyM@nwcleanairwa.gov
Cc: Paris, Sandy <Sandy.F.Paris@p66.com>; RSC:Ferndale Records <FerndaleRecords@p66.com>
Subject: Phillips 66 Regional Haze Information Request

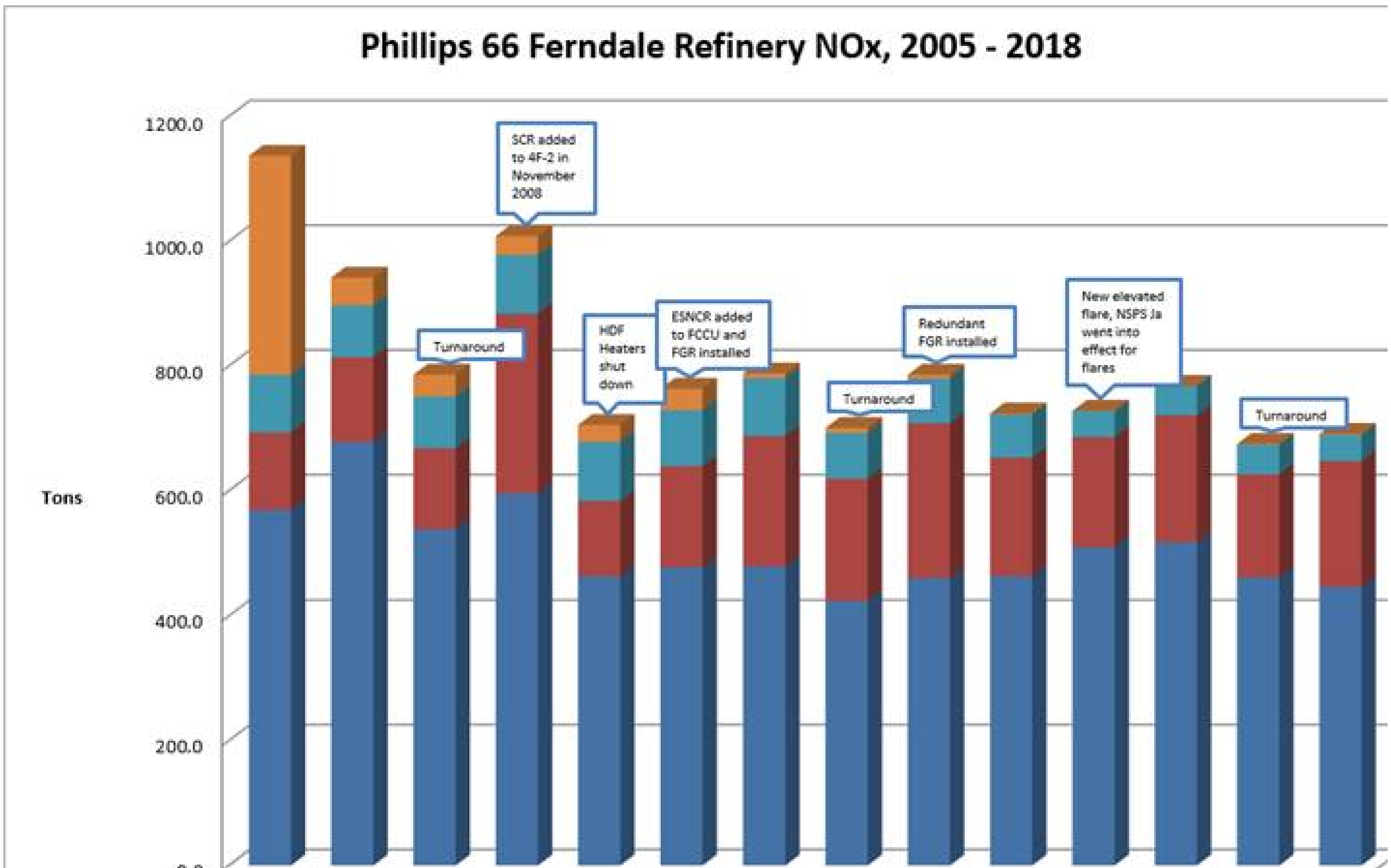
Scott and Toby –

Per your request, Phillips 66 has prepared the attached documentation of emissions for the regional haze program. We have completed the requested table, and added notes where appropriate.

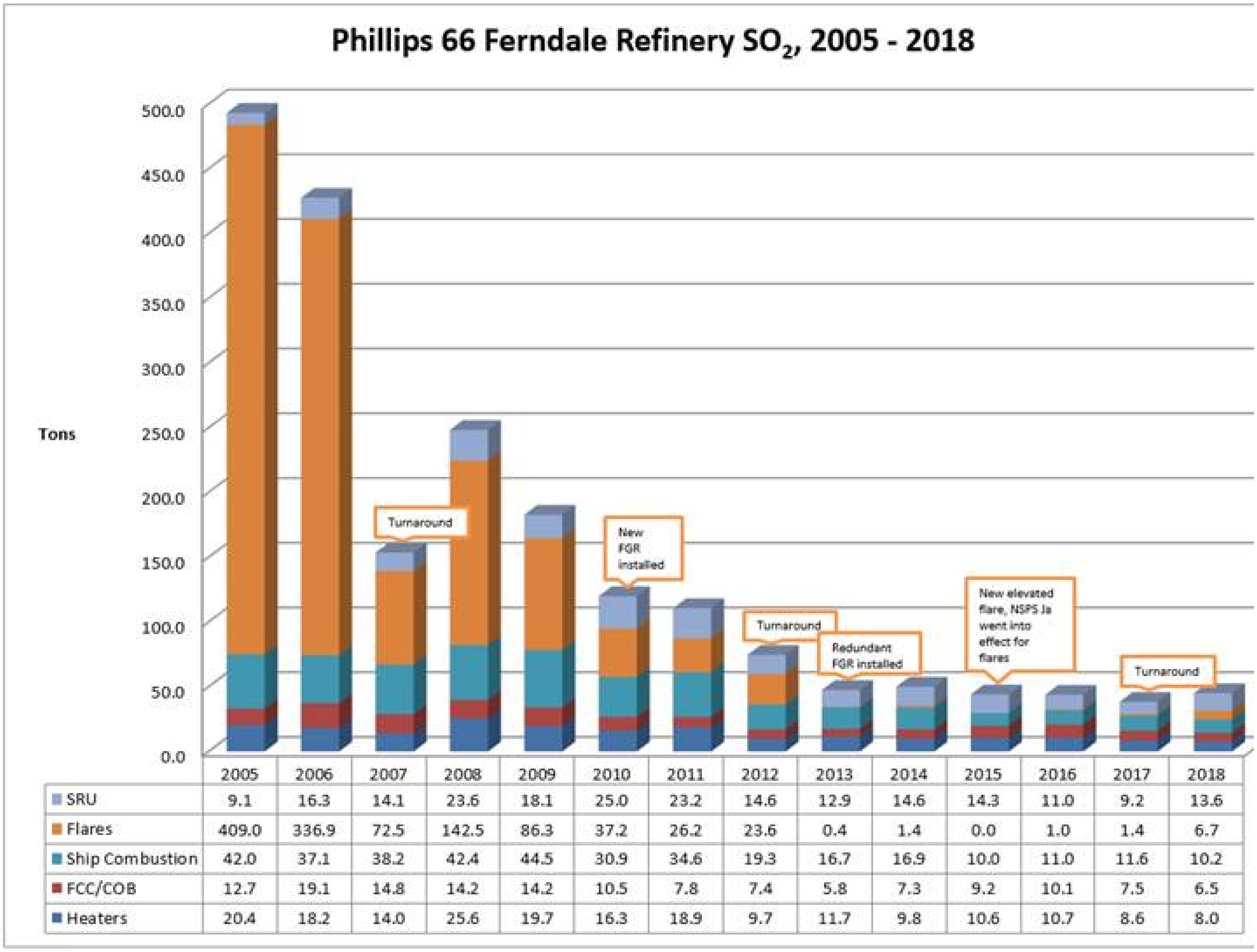
Brief timeline of Phillips 66 process unit changes, 2007 through present:

- 2007
  - Turnaround year
  - Emissions impact: reduction in NOx and SO2 from reduced operating hours
- 2008
  - SCR added to the 4F-2 heater per Consent Decree requirement
  - Emissions impact: NOx reduction at 4F-2 heater
- 2009
  - HDF Heaters decommissioned (14F-1 and 14F-2)
  - Emissions impact: NOx reduction of 3.55 tpy and SO2 reduction of 0.23 tpy (based on difference between 2008 and 2009 WEIRS emissions)
- 2010
  - ESNCR added to the FCCU and flare gas recovery compressors installed per Consent Decree requirement
  - Emissions impact: NOx reduction at the FCCU, NOx and SO2 reduction at the flare
- 2012
  - Turnaround year

- Emissions impact: reduction in NOx and SO2 from reduced operating hours
- 2013
  - Redundant flare gas recovery compressor installed
  - Emissions impact: NOx and SO2 reduction at the flare
- 2015
  - New elevated flare installed and NSPS Ja went into effect for flares
  - Emissions impact: SO2 reduction at the flare
- 2017
  - Turnaround year
  - Emissions impact: reduction in NOx and SO2 from reduced operating hours



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Flares	351.0	44.2	35.1	30.2	26.9	34.2	7.5	8.2	5.7	1.2	0.4	0.0	1.1	1.4
Ship Combustion	92.4	83.0	82.9	94.0	94.8	89.9	92.8	73.3	71.7	69.7	41.4	47.0	47.8	42.0
FCC/COB	124.6	135.9	129.5	288.5	120.1	161.5	207.8	194.9	247.1	189.5	176.5	202.6	164.2	201.4
Heaters	569.1	678.5	538.9	595.7	463.7	478.0	480.0	424.5	461.5	463.6	509.9	518.5	462.1	446.3



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
SRU	9.1	16.3	14.1	23.6	18.1	25.0	23.2	14.6	12.9	14.6	14.3	11.0	9.2	13.6
Flares	409.0	336.9	72.5	142.5	86.3	37.2	26.2	23.6	0.4	1.4	0.0	1.0	1.4	6.7
Ship Combustion	42.0	37.1	38.2	42.4	44.5	30.9	34.6	19.3	16.7	16.9	10.0	11.0	11.6	10.2
FCC/COB	12.7	19.1	14.8	14.2	14.2	10.5	7.8	7.4	5.8	7.3	9.2	10.1	7.5	6.5
Heaters	20.4	18.2	14.0	25.6	19.7	16.3	18.9	9.7	11.7	9.8	10.6	10.7	8.6	8.0

If your presentation and meeting are open to the public, we will do our best to be in attendance – just let us know when and where it's being held.

Please don't hesitate to let us know if we can be of further assistance.

Best regards,

Erin

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