APPENDIX A – PSD APPLICATION

Prevention of Significant Deterioration Air Construction Permit Application

South Shore Energy, LLC,
Dairyland Power Cooperative
Nemadji River Generation, LLC

Nemadji Trail Energy Center
Project No. 101798

Docket Number: 9698-CE-100
Revision 0
December 2021

Prevention of Significant Deterioration Air Construction Permit Application

prepared for

South Shore Energy, LLC,
Dairyland Power Cooperative
Nemadji River Generation, LLC
Nemadji Trail Energy Center
Superior, Wisconsin

Project No. 101798

Revision 0
December 2021

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

Page No.

LIST OF TABLES

Page No.

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
$(NH_4)_2SO_4$	ammonium sulfate
°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
%	percent
AERMAP	AERMOD terrain pre-processor
AERMOD	AMS/EPA Regulatory Model
AMS	American Meteorological Society
AQRV	Air Quality Related Value
AQS	Air Quality System
ARM2	Ambient Ratio Method
AVO	audio/visual/olfactory
BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program - Plume Rise Model Enhancements
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAQT	critical air quality threshold
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CH_4	methane
CI	compression ignition

Abbreviation	**Term/Phrase/Name**
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
EMISFACT	emission factor
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FDCP	Fugitive Dust Control Plan
FGR	flue gas recirculation
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Managers
ft/s	feet per second
g/hp-hr	gram per horsepower hour
g/kW-hr	gram per kilowatt hour
g/m^2	grams per square meter
GCP	good combustion practices
GEP	Good Engineering Practice
GHG	greenhouse gas
GWP	global warming potential
H_2O	water
H_2SO_4	sulfuric acid
HAP	Hazardous Air Pollutant

Abbreviation	Term/Phrase/Name
hp	horsepower
HRSG	heat recovery steam generator
ICE	internal combustion engine
IEC	International Electrotechnical Commission
kg/GJ	kilograms per gigajoule
kPa	kilopascal
kV	kilovolt
kW	kilowatt
LAER	Lowest Achievable Emission Rate
lb/hr	pounds per hour
lb/lb-mol	pound per pound-mole
lb/MMBtu	pounds per million British thermal units
lb/MW-hr	pound per megawatt hour
lb/VMT	pounds per vehicle mile traveled
lb/yr	pounds per year
LDAR	leak detection and repair
LNB	low-NO_x burner
MACT	Maximum Achievable Control Technology
MECL	minimum emissions compliance load
MERP	Modeled Emission Rates for Precursors
mg/L	milligrams per liter
mg/m^3	milligrams per cubic meter

Abbreviation	Term/Phrase/Name
MMBtu/hr	million British thermal units per hour
MW	megawatt
N_2O	nitrogen oxide
NAAQS	National Ambient Air Quality Standards
NAD 83	North American Datum of 1983
NAICS	North American Industrial Classification System
NED	National Elevation Dataset
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	nanogram per Joule
NH_3	ammonia
NH_4HSO_4	ammonium bisulfate
NMHC	non-methane hydrocarbon
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NSRP-3	National Atmospheric Deposition Program
NTEC	Nemadji Trail Energy Center
O_2	oxygen
OLM	Ozone Limiting Method
PBL	Planetary Boundary Layers

Abbreviation	Term/Phrase/Name
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppb	parts per billion
ppm	parts per million
PRIME	Plume Rise Model Enhancements algorithm
PSD	Prevention of Significant Deterioration
psia	pounds per square inch
PVMRM	Plume Volume Molar Ratio Method
Q/D	emissions (Q) divided by distance (D) screening procedure for Class I areas
RACT	Reasonable Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	Reciprocating Internal Combustion Engines
RMP	Risk Management Plan
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SIC	Standard Industrial Classification
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
TCEQ	Texas Commission on Environmental Quality
tpy	tons per year

Abbreviation	**Term/Phrase/Name**
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound
VMT	vehicle miles traveled
WAC	Wisconsin Administrative Code
WDNR	Wisconsin Department of Natural Resources

1.0 EXECUTIVE SUMMARY

Pursuant to the requirements specified in the Wisconsin Administrative Code (WAC) Chapter NR 405, South Shore Energy, LLC, a subsidiary of ALLETE, Inc., Dairyland Power Cooperative, and Nemadji River Generation, LLC, a subsidiary of Basin Electric Power Cooperative, (collectively the Owners), are submitting this Prevention of Significant Deterioration (PSD) air construction permit application for the proposed construction of a combined-cycle combustion turbine and associated support equipment at the Nemadji Trail Energy Center (NTEC) (Project) (FID 816127840). The Project, approximately 625-megawatts (MW), will be a greenfield site located east of the existing Enbridge Energy Superior Terminal Facility on the banks of the Nemadji River in the City of Superior in Douglas County, Wisconsin.

The Owners have two current Air Pollution Control Construction Permits for this facility. Permit 18-MMC-168 is for the installation of a combined-cycle facility and permit 21-MMC-011 is for the installation of fugitive emissions of air contaminants from piping components and haul road traffic fugitive emissions. The Owners wish to extend the construction permit expiration date so that construction can commence in 2023. As requested by Wisconsin Department of Natural Resources (WDNR), a new comprehensive permit application that includes all previously submitted permit application materials is being submitted to accomplish this permit action. As part of this submittal the Best Available Control Technology (BACT) and air dispersion modeling analysis are being updated to current standards.

This construction permit application is divided into the following sections:

- Part 1 – Executive Summary
- Part 2 – Project Description
- Part 3 – Emissions Estimates (This section provides estimates of emissions associated with the Project.)
- Part 4 – Regulatory Review (This section identifies applicable State and Federal air quality regulations.)
- Part 5 –BACT Analysis
- Part 6 – Air Dispersion Modeling (This section provides model descriptions and data requirements for the air quality impact assessment as well as interpretation, analysis, and comparison of the modeling results with applicable air quality regulations.)
- Part 7 – Additional Impact Analysis (This section addresses other potential air quality-related impacts (i.e., growth, soil, vegetation, and visibility).)

Construction permit application forms required by the WDNR are included in Appendix A of this application.

1.1 Project Equipment

The Project will consist of one H-Class combustion turbine with a heat recovery steam generator (HRSG) with duct burner and one steam turbine in a combined-cycle configuration along with associated support equipment. The Project is expected to be approximately 625 MW. The combustion turbine will be designed to utilize pipeline-quality natural gas and combust fuel oil (ultra-low sulfur diesel) as back-up fuel. In addition to the combustion turbine, an auxiliary boiler, circuit breakers, two natural gas-fired gas heaters (natural gas heater), an emergency diesel fire pump, an emergency diesel generator, fuel oil storage tanks, haul roads, and natural gas and fuel oil piping components will be included as part of the Project.

1.2 Project Emissions

As required pursuant to WAC Chapter NR 405, this permit application contains the following analyses/assessments regarding emissions of regulated pollutants associated with the construction and operation of the Project:

- Evaluation of ambient air quality in the area for each regulated pollutant for which the Project will result in a PSD significant net emissions increase
- Demonstration that emissions increases resulting from the Project will not cause or contribute to an increase in ambient concentrations of pollutants exceeding the remaining available PSD increment and the National Ambient Air Quality Standards (NAAQS)
- Assessment of any adverse impacts on soils, vegetation, visibility, and growth in the area
- A BACT analysis for each PSD-regulated pollutant for which the Project will result in a significant net emissions increase

Potential emissions from the Project are shown in Table 1-1 which includes start-up and shutdown emissions for the combustion turbine and auxiliary equipment emissions. A full description of equipment associated with the Project is provided in Part 2.0 of this application.

Table 1-1: Project Potential Emissions and PSD Significance Levels

Pollutant	Project Potential Emissions[a] (tons per year)	PSD Significance Level[1] (tons per year)
NO_x	**269**	40
CO	**2,003**	100
PM	**167**	25
PM_{10}[b]	**167**	15
$PM_{2.5}$[b]	**167**	10
SO_2	29	40
VOC	**250**	40
H_2SO_4 mist	**43**	7
Lead	0.01	0.6
CO_2e	**2,739,294**	75,000[2]

Source:
(1) 40 CFR 52.21(b)(23)(i)
(2) 40 CFR 52.21(b)(49)(iv)(a)
(a) Numbers in **bold** indicate the PSD significance level is exceeded
(b) Filterable plus condensable

The Project is an area (minor) source of Hazardous Air Pollutants (HAPs) (less than 25 tons per year of total HAPs and less than 10 tons per year of any single HAP).

1.3 BACT

The updated BACT analysis shows that the BACT determination in the original applications and PSD permit remain valid. The controls and emission limitations have not changed since the permit issuance date.

A "top-down" BACT analysis was performed for each of the pollutants in Table 1-1 that was above its corresponding PSD significance level: nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM)/ particulate matter of 10 microns in diameter or smaller (PM_{10})/ particulate matter of 2.5 microns in diameter or smaller ($PM_{2.5}$), volatile organic compounds (VOC), sulfuric acid (H_2SO_4) mist, and greenhouse gases (CO_2e). In addition, WDNR also requires a BACT analysis for opacity.

State-of-the-art pollution control equipment has been selected as BACT for the Project. Emissions of NO_x from the combustion turbine will be controlled by low-NO_x burners. Emissions of NO_x from both the combustion turbine and the duct burner will be controlled with selective catalytic reduction (SCR). Emissions of CO and VOC will be controlled by good combustion practices as well as an oxidation catalyst (also referred to as a CO catalyst). Use of clean fuels and good combustion practices will control emissions of H_2SO_4 mist and PM/PM_{10}/$PM_{2.5}$. Greenhouse gas emissions will be controlled with the use of natural gas fuel, monitoring and control of excess air, and efficient turbine design. To minimize the near-stack opacity, the combustion turbine will be controlled through the use clean fuels and good combustion practices. Table 1-2 displays the BACT results.

Table 1-2: Summary of BACT Results – Combustion Turbine

Pollutant	Fuel	Control	BACT Emissions[a,b]	Average
NO_x	Natural gas	Selective catalytic reduction (SCR) and low-NO_x burners	2 ppm (with or without duct firing)	24-hour rolling
	Fuel oil	SCR and water injection	6 ppm (with or without duct firing)	24-hour rolling
CO	Natural gas	Good combustion practices, oxidation catalyst	1.5 ppm (with or without duct firing)[c]	168-hour rolling
	Fuel oil	Good combustion practices, oxidation catalyst	1.5 ppm (with or without duct firing)[c]	168-hour rolling
PM/PM_{10}/ $PM_{2.5}$	Natural gas	Combustion controls and low ash fuels	36.3 lb/hr (with duct firing) 21.8 lb/hr (without duct firing)	NA
	Fuel oil	Combustion controls and low ash fuels	54.5 lb/hr (with duct firing) 39.4 lb/hr (without duct firing)	NA
VOC	Natural gas	Good combustion practices, oxidation catalyst	2.7 ppm (with duct firing) 0.6 ppm (without duct firing)	168-hour rolling
	Fuel oil	Good combustion practices, oxidation catalyst	3.3 ppm (with duct firing) 0.6 ppm (without duct firing)	168-hour rolling
H_2SO_4 mist	Natural gas	Combustion controls and low sulfur fuels	9.9 lb/hr (with duct firing) 7.8 lb/hr (without duct firing)	NA
	Fuel oil	Combustion controls and low sulfur fuels	9.3 lb/hr (with duct firing) 7.0 lb/hr (without duct firing)	NA
Greenhouse gases	Natural gas	Use of natural gas as a fuel, monitoring and control of excess air, efficient turbine design, and oxidation catalyst	850 lb CO_2/MW-hr, gross	12-month rolling
	Fuel oil	Use of ultra-low sulfur diesel as a fuel, monitoring and control of excess air, efficient turbine design, and oxidation catalyst	1,180 lb CO_2/MW-hr, gross	12-month rolling
Opacity	Both	Low-NO_x burners, SCR, combustion controls, low ash fuels	N/A	N/A

Source: Construction permit no.: 18-MMC-168
(a) ppm = parts per million; lb/hr = pounds per hour; lb/MW-hr = pound per megawatt hour
(b) Concentration at 15 percent oxygen while operating at MECL and greater under steady state conditions, unless otherwise noted
(c) Natural gas limit valid for 100% load with duct firing down to MECL. Fuel oil limit valid for 100% load with duct firing down to 75% load.

1.4 Air Quality Analysis

The existing air quality in the Douglas County area is designated as attainment or unclassifiable in regard to the NAAQS for all criteria pollutants. An air dispersion modeling analysis was performed for the pollutants subject to PSD to assess potential ambient air quality impacts associated with the Project. The modeling was performed in accordance with approved WDNR and U.S. Environmental Protection Agency (EPA) modeling guidance.

The modeling analysis (included in Part 6.0 of this application) demonstrates that operation of the Project will not cause or contribute to a violation of the NAAQS or PSD increments, as applicable.

1.5 Additional Impacts Analysis

The potential impacts of the proposed Project on visibility, soils, vegetation, and growth are discussed in Part 7.0 of this application. As indicated by the analysis, the addition of the Project will not have a significant impact on visibility, soils, growth, or vegetation in the surrounding area.

2.0 PROJECT DESCRIPTION

Section 2.0 overview: The references to the most current project descriptions for the permitted units are presented in Table 2-1. A 12-cell cooling tower was initially permitted as part of the Project and was removed as part of a permit modification request dated June 5, 2020.

Table 2-1: Project Description References

Unit ID	Description	Previous Application Reference	December 2021 Submittal Location
P01	Combined-Cycle Turbine	2.0 Project Description December 2018 Submittal	2.0 Project Description
B02	Auxiliary boiler	2.0 Project Description December 2018 Submittal	2.0 Project Description
F03	Circuit breakers	1.0 Introduction June 2020 Submittal	2.0 Project Description
P04	Natural gas-fired heater	2.0 Project Description December 2018 Submittal	2.0 Project Description
P05	Natural gas-fired heater	2.0 Project Description December 2018 Submittal	2.0 Project Description
P06	Emergency diesel fire pump	2.0 Project Description December 2018 Submittal	2.0 Project Description
P07	Emergency diesel generator	2.0 Project Description December 2018 Submittal	2.0 Project Description
T01	Diesel fuel day tank	2.0 Project Description December 2018 Submittal	2.0 Project Description
T02	Diesel fuel generator tank	2.0 Project Description December 2018 Submittal	2.0 Project Description
T03	Diesel fuel fire pump tank	2.0 Project Description December 2018 Submittal	2.0 Project Description
F01	Haul roads	2.0 Project Description January 2021 Submittal	2.0 Project Description
F02	Natural gas and fuel oil piping components	2.0 Project Description January 2021 Submittal	2.0 Project Description
--	Project location	Appendix B – Figure B-1 January 2021 Submittal	Appendix B – Figure B-1
--	Site plot plan	Appendix B – Figure B-2 January 2021 Submittal	Appendix B – Figure B-2

The Project will be located east of the existing Enbridge Energy Superior Terminal Facility on the banks of the Nemadji River in the City of Superior in Douglas County, Wisconsin. The Project location and site plot plan are shown in Figures B-1 and B-2 (Appendix B). Douglas County is currently designated as an attainment/unclassified area for all criteria pollutants in 40 Code of Federal Regulations (CFR) Part 81.

2.1 Turbine (P01) and Emission Controls

The Project will use H-Class combined-cycle turbine technology to generate electricity. The duct burner will combust natural gas and heat the exhaust gas from the combustion turbine within the HRSG. The combustion turbine is proposed to be permitted to operate year-round with no hourly restrictions in combined-cycle mode when combusting natural gas.

The combustion turbine will combust fuel oil when natural gas is unavailable due to limited availability and/or curtailment. Fuel oil, when combusted, will be limited to 11.0 million gallons per year of fuel oil.

To control emissions of NO_x, the combustion turbine will be equipped with low-NO_x burners. In addition, SCR will be added in the HRSG to further reduce NO_x emissions. To minimize emissions of sulfur dioxide (SO_2), H_2SO_4 mist, and $PM/PM_{10}/PM_{2.5}$, the combustion turbine will be controlled by using clean fuels and good combustion practices. Emissions of CO and VOC will be controlled by using an oxidation catalyst and good combustion practices. Greenhouse gas emissions will be controlled with the use of natural gas or ultra-low sulfur diesel fuel, monitoring, control of excess air, efficient turbine design, and use of an oxidation catalyst.

2.2 Auxiliary Boiler (B02)

A 100 million British thermal units per hour (MMBtu/hr) natural gas-fired auxiliary boiler will be constructed to support the operations of the Project and will be permitted for 8,760 hours of operation per year. The auxiliary boiler will be designed with ultra-low NO_x burners, flue gas recirculation (FGR), and oxidation catalyst.

2.3 Sulfur Hexafluoride (SF_6) Containing Equipment (F03)

The following SF_6-containing circuit breaker equipment is proposed:

- Three 345-kilovolt (kV) circuit breakers are proposed for the substation.
- Two 19-kV (estimate) low-side generator circuit breakers will be located in the plant before the step-up transformers that feed the onsite switchyard.

Note that the Project will include six disconnect switches at each substation site; however, the switches are open air type switches and do not contain SF_6.

2.4 Natural Gas Heaters (P04 and P05)

Two natural gas-fired heaters will be used to heat the natural gas prior to combustion in the turbine. Both heaters will be permitted for unlimited operation. The gas heaters will be designed with low-NO_x burners.

2.5 Emergency Diesel Fire Pump (P06)

An emergency diesel fire pump will be built to support the Project in case of a fire. The emergency diesel fire pump will have a maximum power output of 282 horsepower (hp) and will be fired solely by ultra-low sulfur diesel. The Owners propose to operate the emergency diesel fire pump for up to 500 hours annually for testing and maintenance purposes, and therefore supports a limit on routine hours of operation of the emergency diesel fire pump.

2.6 Emergency Diesel Generator (P07)

An emergency diesel generator will be built to support the Project's combustion turbine in case of a power interruption. The emergency diesel generator will have a maximum power output of 1,490 hp (1,112 kilowatt [kW]) and will be fired solely by ultra-low sulfur diesel. The Owners propose to operate the emergency diesel generator for up to 500 hours annually for testing and maintenance purposes, and therefore supports a limit on routine hours of operation of the emergency diesel generator.

2.7 Diesel Storage Tanks (T01, T02, and T03)

The project will include three diesel storage tanks: one 180,000-gallon tank, one 1,700-gallon tank, and one 350-gallon tank. These tanks will store diesel fuel for the combustion turbine, emergency diesel generator, and emergency diesel fire pump.

2.8 Haul Road Traffic Fugitives (F01)

Miscellaneous supplies associated with facility operation will be transported to and from the site via trucks. Up to 520 trucks per year are expected for delivery or removal. Some examples of activities associated with facility operation are as follows, but not limited to, aqueous ammonia for emissions control and water treatment and fuel oil for emergency equipment.

To mitigate onsite road emissions from these deliveries, NTEC will pave the primary facility roads. Both fuel oil and natural gas to the combustion turbine and duct burner will be delivered to the site via pipeline and not by truck delivery.

2.9 Natural Gas and Fuel Oil Fugitives (F02)

The proposed project will include natural gas piping components from the natural gas line that will enter the project site to provide gas for the combustion turbine, duct burner, natural gas heaters and auxiliary boiler. These natural gas piping components are potential sources of methane and VOC emissions due to emissions from valves, flanges, sampling connections and relief valves.

The proposed project will also include fuel oil piping components from the fuel oil line that will enter the project site to provide fuel oil for the combustion turbine and duct burner, as well as the emergency diesel fire pump and emergency diesel generator. These fuel oil piping components are potential sources of methane and VOC emissions due to emissions from valves, flanges, sampling connections and relief valves.

3.0 EMISSIONS ESTIMATES

Section 3.0 overview: The references to the most current emissions estimates write-up sections for the permitted units are presented in Table 3-1. Overall potential emissions from the Project are shown in Table 1-1 of this application. The emissions calculations for each permitted unit are presented in Appendix C and capture all project updates that have occurred throughout the permitting process. Updates to the previously submitted emissions calculations in Appendix C and in Table 3-4 and Table 3-5 in this section are the result of project updates and post application submittal actions.

Table 3-1: Emissions Estimates References

Unit ID	Description	Previous Application Reference	December 2021 Submittal Location
P01	Combined-Cycle Turbine	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
B02	Auxiliary boiler	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
F03	Circuit breakers	1.0 Introduction June 2020 Submittal	3.0 Emissions Estimates
P04	Natural gas-fired heater	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
P05	Natural gas-fired heater	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
P06	Emergency diesel fire pump	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
P07	Emergency diesel generator	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
T01	Diesel fuel day tank	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
T02	Diesel fuel generator tank	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
T03	Diesel fuel fire pump tank	3.0 Emissions Estimates December 2018 Submittal	3.0 Emissions Estimates
F01	Haul roads	3.0 Emissions Estimates January 2021 Submittal	3.0 Emissions Estimates
F02	Natural gas and fuel oil piping components	3.0 Emissions Estimates January 2021 Submittal	3.0 Emissions Estimates

Emissions of air contaminants will result from the combustion of natural gas and fuel oil in the combustion turbine and natural gas in the duct burner. There will also be emissions of air contaminants generated from the auxiliary equipment: an auxiliary boiler, circuit breakers, two natural gas heaters, an emergency diesel fire pump, an emergency diesel generator, fuel oil storage tanks, haul roads, and natural gas and fuel oil piping components.

Process flow diagrams for the combustion turbine process and auxiliary equipment are located in Appendix A. Each emission point's control device descriptions, control efficiencies, and procedures for estimating emissions is discussed in detail in the sections below. Tables summarizing the emissions estimates are included in Appendix C.

3.1 Combustion Turbine (P01)

The following sections summarize the combustion turbine hours of operation, emissions estimates for various operating loads when combusting natural gas and fuel oil, and start-up/shutdown operation.

3.1.1 Combustion Turbine Hours of Operation

The following conservative assumptions were applied to seven combustion turbine operating scenarios to determine maximum potential annual emissions as shown in Table 3-2.

Table 3-2: Combustion Turbine Operating Cases for Maximum Potential Annual Emissions

Type of Operation	Scenario						
	1	2	3	4	5	6	7
Natural gas with duct firing	X	X	X			X	X
Natural gas (normal operation)				X	X		
Natural gas start-up/shutdown		X	X	X	X		X
Fuel oil with duct firing[a]						X	X
Fuel oil (normal operation)[a]			X		X		
Fuel oil start-up/shutdown[a]			X		X	X	X

(a) Fuel oil, when combusted, will be limited to 11.0 million gallons per year of fuel oil.

Start-up and shutdown emissions were based on the start-up and shutdown profiles for the combined-cycle combustion turbine and the number of start-up and shutdown events per year for each fuel. The Owners are requesting the following start-up and shutdown limits:

- An hours per year limit on start-up and shutdown (1,525 hours per year for start-up and shutdown, combined) for natural gas operation
- 42 start-ups and 42 shutdowns per year for fuel oil operation.

3.1.2 Combustion Turbine Operation Emissions

Emissions from the combustion turbine are dependent on ambient temperature conditions and the turbine's operating load, which can vary from 33 to 100 percent. To account for representative seasonal climatic variations, potential emissions from the proposed combustion turbine were analyzed at the minimum emissions compliance load (MECL) (designated as "low"), 75, and 100 percent load conditions for ambient temperatures ranging from negative (-)34.3 degrees Fahrenheit (°F) to 95.5°F. The projected emissions were based on data provided by the combustion turbine manufacturer and/or from AP-42 emission factors. Detailed calculations of the combustion turbine's emissions are provided in Appendix C of this application.

For purposes of emission calculations and modeling, the MECL ranges from 33 to 50 percent load, depending on ambient conditions, and was grouped as "low" load. When grouping, the worst-case parameters were chosen (highest emission rate, lowest temperature, lowest flow rate).

Based on the above assumptions, the maximum expected hourly emission rates for normal operation (excluding start-up and shutdown) for the combustion turbine are shown in Table 3-3.

Table 3-3: Maximum Expected Hourly Combustion Turbine Emission Rates

Pollutant	Natural Gas with Duct Firing	Natural Gas 100% Load	Fuel Oil with Duct Firing	Fuel Oil 100% Load
	pounds per hour			
NO_x	33.5	26.5	72.7	51.6
CO	15.3	12.1	11.1	7.8
$PM/PM_{10}/PM_{2.5}$	36.3	21.8	54.5	39.4
SO_2	6.4	5.1	6.1	4.6
VOC	15.5	2.8	14.1	1.8
H_2SO_4 mist	9.9	7.8	9.3	7.0
Lead	--	--	0.04	0.04
CO_2e	592,127	469,787	947,846	819,965

3.1.3 Combustion Turbine Start-Up and Shutdown Emissions Calculation Method

The combustion turbine emissions are based on 1,525 hours per year for start-up and shutdown, combined, for natural gas operation. Potential start-up and shutdown emissions were based on a start-up profile and conservatively assumed that there will be a combination of cold starts, warm starts, hot-fast starts, and shutdown on natural gas. There will also be up to 42 start-ups and 42 shutdown events per year on fuel oil. One start-up/shutdown event is equivalent to one start-up plus one shutdown.

Potential start-up and shutdown emissions for natural gas and fuel oil combustion are shown in Table 3-4 and Table 3-5, respectively. Detailed calculations of the potential start-up and shutdown emissions are provided in Appendix C.

Table 3-4: Potential Natural Gas Turbine Start-up and Shutdown Emissions

Pollutant	Start-up Emissions			Shutdown Emissions	Start-up and Shutdown Emissions[a]
	lb/cold start	lb/warm start	lb/hot-fast start	lb/shutdown	tons per year
NO_x	335.0	233.0	111.0	59.0	108.3
CO	11,066	6,495	779.0	463.0	1,369
$PM/PM_{10}/PM_{2.5}$	43.6	29.1	16.3	10.9	16.6
SO_2	10.2	6.8	3.8	2.6	3.9
VOC	950.0	558.0	67.0	40.0	117.8
H_2SO_4 mist	15.6	10.4	5.9	3.9	6.0
Lead	0.0	0.0	0.0	0.0	0.0
CO_2e	939,573	626,382	352,340	234,893	358,212

(a) Emissions are based on 1,525 hours per year for start-up and shutdown, combined, for natural gas operation.

Table 3-5: Potential Fuel Oil Turbine Start-up and Shutdown Emissions

Pollutant	Start-up Emissions	Shutdown Emissions	Start-up and Shutdown Emissions[a]
	lb/start	lb/shutdown	tons per year
NO_x	860.0	108.0	20.3
CO	25,846	1,227	568.5
$PM/PM_{10}/PM_{2.5}$	78.9	19.7	2.1
SO_2	9.2	2.3	0.2
VOC	2,951	122.0	64.5
H_2SO_4 mist	14.0	3.5	0.4
Lead	0.08	0.02	0.002
CO_2e	1,639,929	409,982	43,048

(a) Emissions are based on 42 start-ups and 42 shutdowns

3.2 HAP Emissions

The Project is an area source of HAPs (*i.e.,* less than 25 tons per year of total HAPs and less than 10 tons per year of any single HAP). HAP emission calculations and a summary of HAP emissions are included in Appendix C.

3.3 Auxiliary Boiler Emissions (B02)

One 100 MMBtu/hr auxiliary boiler will be installed at the facility to be used while the combustion turbine is operating. The boiler will be fired with natural gas. The auxiliary boiler will be limited to annual operations of 8,760 hours. Emissions for this unit were estimated based on AP-42 emission factors and vendor data. Greenhouse gas emissions were estimated based on the emission factors in 40 CFR Part 98. Detailed calculations are provided in Appendix C.

3.4 SF_6 Containing Equipment (F03)

Annual potential to emit emissions of SF_6 from the circuit breakers were based on maximum leakage rate of 0.5 percent per year, the amount of SF_6 in each size of circuit breaker, and the global warming potential (GWP). Project potential emissions of CO_2e leakage from all proposed circuit breakers combined are estimated to be 120 tons per year. A detailed report of the SF_6 emissions is provided in Appendix C of this application.

3.5 Natural Gas Heaters Emissions (P04 and P05)

Two 10.0 MMBtu/hr natural gas-fired heaters will be installed at the facility to heat the natural gas prior to being combusted in the combustion turbine. As a worst-case estimate, it is assumed that annual operations will be 8,760 hours per year for each heater. Emissions for the gas heaters were estimated based on AP-42 emission factors. Greenhouse gas emissions were estimated based on the emission factors in 40 CFR Part 98. Detailed calculations are provided in Appendix C.

3.6 Emergency Diesel Fire Pump Emissions (P06)

One 282-hp diesel fire pump will be installed for emergency power use at the facility. The fire pump will be fired with ultra-low sulfur diesel. Emissions for the emergency diesel fire pump were estimated assuming an annual testing and maintenance schedule of 500 hours. Emissions for this unit were estimated based on New Source Performance Standards (NSPS) limits and AP-42 emission factors. Greenhouse gas emissions were estimated based on the emission factors in 40 CFR Part 98. Detailed calculations of diesel fire pump emissions are provided in Appendix C.

3.7 Emergency Diesel Generator Emissions (P07)

One 1,490 hp (1,112 kW) diesel generator will be installed for emergency power use at the facility; the generator will be fired with ultra-low sulfur diesel. Emissions for the emergency diesel generator were estimated assuming an annual testing and maintenance schedule of 500 hours. Emissions for this unit were estimated based on NSPS limits and AP-42 emission factors. Greenhouse gas emissions were estimated based on the emission factors in 40 CFR Part 98. Detailed calculations of diesel generator emissions are provided in Appendix C.

3.8 Diesel Storage Tanks Calculation Method (T01, T02, and T03)

The project will include three diesel storage tanks: one 180,000-gallon tank, one 1,700-gallon tank, and one 350-gallon tank. Emissions from loading and breathing losses were estimated for the storage tanks using the EPA TANKS emission software. A detailed report of the fuel oil storage tank emissions is provided in Appendix C.

3.9 Haul Road Traffic Fugitives Calculation Method (F01)

Emissions from haul roads due to traffic were estimated using the paved roads, size-specific emission calculation equation below:

$$E = k * (sL)^{0.91} 0.91 * (W)^{1.02}$$

Where:

E = pounds per vehicle miles traveled (lb/VMT)

sL = silt loading grams per square meter (g/m^2) = 2.4 g/m^2

W = mean vehicle weight (tons)

k = constant (AP-42 Table 13.2-1.1)

The mean vehicle weight is calculated by averaging the loaded and unloaded vehicle weights. The "ubiquitous baseline" of 0.6 g/m^2 was selected from the less than 500 average daily traffic category in AP-42 Table 13.2.1-2; and the ubiquitous winter baseline multiplier during months with frozen precipitation (x4) was applied to this value to obtain a silt loading value of 2.4 g/m^2 for all paved roads.

For paved roads, vehicle miles traveled (VMT) is calculated as follows:

$$VMT = length\ of\ path\ haul\ road\ vehicle\ travels * maximum\ trips\ (hourly\ or\ annual)$$

Whether a vehicle travels the haul road twice (back and forth) or once (when traveling in a loop) was accounted for when calculating the miles traveled for each haul road route. Detailed calculations of haul road emissions are provided in Appendix C.

3.10 Natural Gas and Fuel Oil Fugitives Calculation Method (F02)

Fugitive emissions will come from small leaks in equipment connections throughout the facility. The estimated number of connectors, flanges, open ended lines, pump seals and valves were determined from engineering plans for the facility. The emissions were then estimated using the 1995 Protocol for

Equipment Leak Emission Estimates- EPA-453/R-95-017. The emissions estimates for fuel oil fugitives is "total organics" which includes non-VOCs such as methane and ethane and is assumed to be VOCs for the purposes of this application. The emissions estimates for natural gas VOC fugitive emissions was calculated using the minimum methane content. Further, to determine natural gas CO_2e fugitive emissions the maximum methane content was used. Detailed calculations of natural gas and fuel oil fugitives are provided in Appendix C.

4.0 REGULATORY REVIEW

Overview: The references to the most current regulatory review sections for the permitted units are presented in Table 4-1. Specific post-application regulatory updates are also referenced.

Table 4-1: Regulatory Review References

Unit ID	Description	Previous Application Reference	December 2021 Submittal Location
P01	Combined-Cycle Turbine	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
B02	Auxiliary boiler	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
F03	Circuit breakers	Appendix A - Form 4530-132 June 2020 Submittal	4.0 Regulatory Review
P04	Natural gas-fired heater	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
P05	Natural gas-fired heater	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
P06	Emergency diesel fire pump	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
P07	Emergency diesel generator	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
T01	Diesel fuel day tank	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
T02	Diesel fuel generator tank	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
T03	Diesel fuel fire pump tank	4.0 Regulatory Review December 2018 Submittal	4.0 Regulatory Review
F01	Haul roads	4.0 Regulatory Review January 2021 Submittal	4.0 Regulatory Review
F02	Natural gas and fuel oil piping components	4.0 Regulatory Review January 2021 Submittal	4.0 Regulatory Review
All units	Chapter NR 445 Analysis	Data request response letter to WDNR February 23, 2021	Section 4.4.20
P06 and P07	Subpart IIII	Post application NTEC Response #01	Additional language incorporated into Section 4.2.5
HRSG	Subpart KKKK	Post application NTEC Response #09	Additional language incorporated into Section 4.2.6

The Project is subject to various Federal and State air regulations. Part 4 contains a discussion of applicable Federal and WAC provisions. Where applicable, reference to general limitations is provided when there is no specific requirement that applies to an emission source.

In certain instances, there may be multiple applicable regulatory requirements that identify differing levels of emission limitations. For instance, where a BACT emission limitation is established for a specific pollutant and a NSPS regulation is also applicable, the BACT limitation may be more stringent than an applicable NSPS emission limitation for the same pollutant. In these situations, it is understood that compliance with the most restrictive requirement would demonstrate compliance with other less stringent requirements.

4.1 PSD Regulations

PSD review applies to a physical change of a major stationary source located in an area designated as attainment or unclassified that would result in a significant emissions increase of a regulated New Source Review (NSR) pollutant and a significant net emissions increase of that pollutant pursuant to WAC Chapter NR 405. PSD review consists of the following:

- A BACT analysis
- An air quality analysis
- An analysis of additional impacts on visibility, soils, vegetation, and growth

Three criteria were evaluated to determine PSD applicability to the Project (EPA, 1990):

- Whether the Project is sufficiently large (in terms of its emissions) to be a “major stationary source” or “major modification”
- Whether the source is in an area designated as “attainment” or “unclassified”
- Whether the Project would result in a “significant emissions increase” or a “significant net emissions increase” of a “regulated NSR pollutant” as defined by s. NR 405.02(27)(a)

Regulated NSR pollutants in Wisconsin include NO_x, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, VOC, CO_2e, hydrogen sulfide, H_2SO_4 mist, fluorides, and lead. The definition of a “major stationary source” is given in s. NR 405. The Project is included in the 26 source categories specified in the PSD regulations as major stationary sources if the potential emissions of a regulated NSR pollutant exceed 100 tons per year (because the HRSG generates steam). The Project has the potential to emit regulated NSR pollutants in excess of 100 tons per year; therefore, the Project meets the “major stationary source” classification for a number of regulated NSR pollutants. Thus, the Project meets the first criterion for PSD applicability.

The Project is in an attainment/unclassified area for all criteria pollutants; thus, it meets the second criterion for PSD applicability.

The maximum potential emissions from the Project are listed in Table 1-1, which include start-up and shutdown emissions from the combustion turbine. The Project would result in a "significant emission increase" for the following regulated NSR pollutants: NO_x, CO, VOC, PM/PM_{10}/$PM_{2.5}$, H_2SO_4 mist, and CO_2e. Thus, the Project meets the third and final criterion for PSD applicability.

The PSD regulations in s. NR 405 require the following issues be addressed:

- Determination of BACT on a case-by-case basis, taking into account costs as well as energy, environmental, and economic impacts;
- Demonstration that the increase in emissions would not cause or contribute to an exceedance of the NAAQS or PSD increment;
- Analysis of the impairment, if any, to visibility, soils, vegetation, and growth.

Section 5.0 contains the BACT analyses for the regulated NSR pollutants.

4.2 New Source Performance Standards

Per 40 CFR Part 60 and s. NR 440 WAC, the Project is subject to NSPS. Relevant NSPS standards are listed below, and if applicable, a description of how the Owners plan to meet the standards.

4.2.1 Subpart Db – Not Applicable

HRSGs and duct burners regulated under Subpart KKKK are exempt from the requirements of 40 CFR Part 60 Subparts Da, Db, and Dc.

4.2.2 Subpart Dc

NSPS 40 CFR Part 60, Subpart Dc applies to Small Industrial-Commercial-Institutional Steam Generating Units between the sizes of 10 MMBtu/hr and 100 MMBtu/hr. This rule applies to the auxiliary boiler (100 MMBtu/hr) and the two gas heaters (10 MMBtu/hr, each). Since the auxiliary boiler and gas heaters combust natural gas, the Owners will keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage of natural gas in the auxiliary boiler and natural gas heaters. For gas-fired units of this size, there are no emissions limits provided in the rule. The Owners will comply with the record keeping and reporting requirements of the rule.

4.2.3 Subpart GG - Not Applicable

Stationary combustion turbines constructed after February 18, 2005, that are subject to NSPS 40 CFR Part 60, Subpart KKKK are exempt from the requirements of Subpart GG. Section 4.2.6, below, covers Subpart KKKK.

4.2.4 Subpart Kb - Not Applicable

NSPS 40 CFR Part 60, Subpart Kb applies to each storage vessel with a capacity greater than or equal to 75 cubic meters used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Two of the diesel storage tanks will have a capacity less than 75 cubic meters; therefore, the 1,700-gallon and 350-gallon storage tanks will not be subject to Subpart Kb.

This subpart applies to storage vessels with a capacity greater than or equal to 151 cubic meters (39,890 gallons) storing a liquid with a maximum true vapor pressure greater than 3.5 kilopascals (kPa) (0.5 pounds per square inch [psia]). The 180,000-gallon tank diesel storage tank that will be installed as part of the Project is greater than 151 cubic meters (39,890 gallons); however, the tank will not be subject to Subpart Kb as its vapor pressure is less than 3.5 kPa.

4.2.5 Subpart IIII

NSPS 40 CFR Part 60, Subpart IIII applies to stationary compression ignition (CI) internal combustion engines (ICE) and the manufacturers or owners and operators of these engines as follows:

1. **Manufacturers** of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is 2007 or later for non-fire pump engines and the model year listed or later model years for fire pump engines (2008 or 2011)
2. **Owners and operators** of stationary CI ICE that commenced construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 (non-fire pump engines), or manufactured as a National Fire Protection Agency fire pump engine after July 1, 2006

For purposes of this application, Subpart IIII is assumed to be applicable to the emergency fire pump and the emergency diesel generator. Both engines will meet the definition of "emergency stationary internal combustion engine" under this subpart as follows:

- There is no time limit on the use of emergency stationary ICE in emergency situations.
- The engine may be operated for a maximum of 100 hours per calendar year for testing and maintenance, except as indicated, below.
- 50 hours of the 100 hours per calendar year allocated may be used for non-emergency situations.

Further, both engines will be 2009 model year or later.

Based on the size (horsepower) and use (emergency) and assuming the Owners purchase a certified model year 2009 or later CI ICE with a displacement that will less than 10 liters per cylinder, the emergency fire pump will be certified in accordance with the limits in 40 CFR 60.4202(d). As the emergency fire pump will be between 175 and 300 hp, the limits are as follows:

- 4.0 gram per kilowatt hour (g/kW-hr) (3.0 gram per horsepower hour [g/hp-hr]) for non-methane hydrocarbons (NMHC) plus NO_x
- 3.5 g/kW-hr (2.6 g/hp-hr) for CO
- 0.20 g/kW-hr (0.15 g/hp-hr) for PM

Based on the size (horsepower) and use (emergency) and assuming the Owners purchase a certified model year 2007 or later CI ICE with a displacement that will less than 10 liters per cylinder, the emergency generator will be certified in accordance with the limits in 40 CFR 60.4202(a)(2), which refer to the limits in 40 CFR 89.112. As the emergency generator will be greater than 560 kW and manufactured after 2006, Table 1 of 40 CFR 60.89.112(a) indicates the following applicable emission standards [subject to the same being included in a family emission limit in an averaging, banking, and trading program for which the emission standards in Table 2 of 40 CFR 89.112(d) are applicable]:

- 6.4 g/kW-hr (4.8 g/hp-hr) for NMHC plus NO_x
- 3.5 g/kW-hr (2.6 g/hp-hr) for CO
- 0.20 g/kW-hr (0.15 g/hp-hr) for PM

The emergency generator will also be subject to the exhaust opacity limits in 40 CFR 89.113, with single-cylinder engines, propulsion marine diesel engines, and constant speed engines being exempt from these limits:

- 20 percent during the acceleration mode
- 15 percent during the lugging mode
- 50 percent during the peaks in either the acceleration or lugging modes

Compliance with this subpart will be shown by purchasing an engine certified to meet the applicable emission standards for the model year and maximum engine power depending on the date of purchase. The Owners will install emergency diesel engines that are certified to meet the applicable emission standards based on the date that the unit will be installed.

Pursuant to 40 CFR 60.4207(b), owners and operators of CI ICE subject to Subpart IIII with a displacement of less than 10 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel. This rule will be applicable to the emergency diesel engine, since the proposed emergency diesel engine will have a displacement of less than 10 liters per cylinder. As stated in 40 CFR 80.510(b), non-road diesel fuel must be limited to 15 parts per million (ppm) maximum sulfur content. The cetane index is limited to a minimum of 40 and the maximum aromatic content is limited to 35 volume percent.

The Owners will be subject to the applicable requirements of this rule for the emergency fire pump and emergency generator. The Owners intend to limit maintenance and readiness testing to 100 hours to meet the definition of emergency for 40 CFR 60, Subpart IIII. The emergency equipment potential to emit emissions were calculated using 500 hours per year per EPA guidance. The EPA believes that 500 hours per year is an appropriate default assumption for estimating the number of hours that emergency equipment could be expected to operate under worst-case conditions.

4.2.6 Subpart KKKK

NSPS 40 CFR Part 60, Subpart KKKK is applicable to all stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of fuel.

Per 40 CFR 40b(i), if the combustion turbine is subject to Subpart KKKK, then the associated HRSG is exempt from the requirements of 40 CFR Part 60 Subparts Da, Db, and Dc. Per 40 CFR 60.4305(a), since the combustion turbine is greater than 10 MMBtu/hr and will be constructed after February 18, 2005, the combustion turbine is subject to Subpart KKKK. The HRSG associated with the turbine meets the applicability requirements of 40 CFR 60, Subpart KKKK.

Pursuant to 40 CFR Section 60.4320(a) and Table 1 to Subpart KKKK, the NSPS NO_x applicable combustion turbine limit for natural gas combustion, is 15 ppm at 15 percent oxygen or 54 nanogram per Joule (ng/J) of useful output (0.43 pound per megawatt hour [lb/MW-hr]), when burning more than 50 percent natural gas (60.4325).

When combusting more than 50 percent fuel oil, the limit for NO_x is 42 ppm at 15 percent oxygen or 160 ng/J of useful output (1.3 lb/MW-hr).

During operations when ambient temperatures are less than 0 °F or when the turbine is operating at less than 75 percent load, the NO_x emission standard is 96 ppm at 15 percent oxygen or 590 ng/J of useful output (4.7 lb/MWh). This applies when combusting either natural gas or fuel oil. All MW readings are in gross MW. The higher emission standard applies for the hour if at any point in the hour the unit was subject to the higher standard.

In accordance with Subpart KKKK, the Owners would demonstrate compliance with the NO_x emission limit by conducting performance testing pursuant to Section 60.4340(a), or alternatively, by installing, calibrating, maintaining, and operating a continuous monitoring system (i.e., continuous emission monitor (CEM) or continuous parameter monitor) in accordance with Section 60.4340(b).

For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour per §60.4380(b)(3). For combined cycle units, the limits are calculated from hourly average emission rates to assess excess emissions on a 30-unit operating day rolling average basis, as described in § 60.4380(b)(1).

The Owners expect to have a NO_x emission rate of 2 ppm at 15 percent oxygen for natural gas combustion and 6 ppm for fuel oil combustion with the use of SCR.

The NSPS SO_2 limit for the turbine is 0.90 lb/MW-hr gross output, **or** the facility must limit fuel so that any fuel combusted contains total potential sulfur emissions equal to or less than 0.060 lb SO_2/MMBtu heat input. Emissions of SO_2 will be well below 0.90 lb/MW-hr for both fuel oil and natural gas operation; therefore, per 40 CFR Section 60.4365(a), the Owners will keep on record the fuel quality characteristics of the natural gas and fuel oil from the suppliers and fuel analysis records.

4.2.7 Subpart TTTT

NSPS 40 CFR Part 60, Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units regulates carbon dioxide (CO_2) emissions from electric generating units under the NSPS (Clean Air Act 111b regulations). The standards apply to any steam generating unit, integrated gasification combined-cycle, or combustion turbine that commenced construction after January 18, 2014, or reconstruction or modification after June 18, 2014, that has a base load rating greater than 250 MMBtu/hr of fossil fuel and serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system.

The combustion turbine will be subject to NSPS Subpart TTTT. The standard provides a limit for natural gas-fired combined-cycle combustion turbines. A natural gas-fired combined-cycle turbine is limited to

450 kilograms of CO_2 per megawatt-hour of gross energy output (1,000 pounds CO_2 per MW-hour [lb CO_2/MW-hr]) on a 12-operating month rolling average basis. An alternative to meeting the gross energy output the Owners can petition to comply with the alternate net energy output standard, 470 kilograms of CO_2 per megawatt-hour of net energy output (1,030 lb/MW-hr) on a 12-operating month rolling average basis. These limits are based on an assumed operation of 90 percent natural gas in a 12-month period. The combined-cycle combustion turbine will comply with the limit in NSPS Subpart TTTT.

If the turbine combusts 90 percent or less natural gas, in accordance with Table 2 of Subpart TTTT, the limit becomes 50 kilograms CO_2 per gigajoule (kg/GJ) to 69 kg/GJ of heat input (120 to 160 pounds per million British thermal units [lb/MMBtu]) as determined by the procedures in 40 CFR Section 60.5525.

4.3 National Emission Standards for Hazardous Air Pollutants and Maximum Achievable Control Technology

National Emission Standards for Hazardous Air Pollutants (NESHAP) are contained in 40 CFR Part 63 (adopted by reference in s. NR 445). NESHAP are emissions standards set by the EPA for specific source categories. The NESHAP require the maximum degree of emission reduction of certain HAP emissions that the EPA determines to be achievable, which is known as the maximum achievable control technology (MACT) standards.

The following MACT standards are relevant to the Project.

4.3.1 Subpart YYYY - Not Applicable

EPA promulgated MACT standards for new stationary combustion turbines on March 5, 2004. These standards apply to stationary combustion turbines for which construction commenced after January 14, 2003. On April 7, 2004, however, EPA proposed to remove gas-fired units from the combustion turbine source category regulated by NSPS 40 CFR 63, Subpart YYYY. In the interim, EPA has stayed the applicability of Subpart YYYY requirements for gas-fired combustion turbines.

This regulation applies only to combustion turbines at facilities that are major sources of HAPs. The Project will be an area source of HAPs; therefore, the Project is not subject to this regulation.

4.3.2 Subpart ZZZZ

The Reciprocating Internal Combustion Engines (RICE) MACT (40 Part 63, Subpart ZZZZ) is applicable to stationary RICE located at major or area sources of HAP emissions. Both the emergency generator and emergency fire pump will be a new source located at an area source per 40 CFR 63.6590(c)(1). Therefore, the emergency generator will comply with the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60 Subpart IIII pursuant to 40 CFR 63.6590(c)(1) and the fire pump will comply with the requirements of Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII pursuant to 40 CFR 63.6590(c)(1).

4.3.3 Subpart JJJJJJ – Not applicable

40 CFR Part 60, Subpart JJJJJJ applies to industrial, commercial, or institutional boilers and process heaters located at an area source of HAPs. According to the subpart definitions, the two gas-fired heaters and auxiliary boiler fall under the definition of gas-fired boiler. Per 63.11195(e), gas-fired boilers are not subject to Subpart JJJJJJ.

4.4 Wisconsin Air Quality Standards and Regulations

This section describes the regulations which apply to the Project, according to the WAC.

4.4.1 s. NR 404 Ambient Air Quality

Ambient air quality standards applicable to the entire state are listed in s. NR 404. The Owners will comply with all applicable state standards.

4.4.2 s. NR 405 - PSD Review

Under the 1977 Clean Air Act Amendments (CAAA), BACT and other PSD requirements apply both to emissions of criteria pollutants and to emissions of certain non-criteria pollutants that are regulated under Section 111 (NSPS) and Section 112 (NESHAP) of the Act. However, in Section 112(b)(6) of the 1990 CAAA, Congress specifically excluded the HAPs listed in Section 112(b)(1) from the PSD requirements. EPA clarified this exclusion in a March 11, 1991 memo by stating that:

> …the following pollutants, which have been regulated under PSD, are now exempt from federal PSD applicability:

- arsenic
- asbestos
- benzene
- beryllium
- hydrogen sulfide
- mercury
- radionuclides (including radon and polonium)
- vinyl chloride

However, Wisconsin still includes hydrogen sulfide as a PSD pollutant listed in Table A of s. NR 405.02 (27)(a). As such, PSD review of this pollutant is a state-only requirement. This Project will be subject to PSD for several pollutants. Part 5 of this application contains the BACT analyses. Part 6 contains the air dispersion modeling analyses and Part 7 contains the additional impacts analysis.

4.4.3 s. NR 406 – Construction Permits

The purpose of this section is 1) to establish permit and permit review requirements and permit duration for construction permits and 2) to define types of stationary sources that are exempt from the requirement to obtain a construction permit. This permit application is intended to satisfy the construction permit application requirements to obtain a permit.

4.4.4 s. NR 407 – Operation Permits

For new sources that require a construction permit, the initial filing date is the date that the construction permit is filed (NR 407.04(1)(b)). However, because of the nature of this project, and because multiple vendor selections have yet to be made, there is not enough data to complete the operation permit application at this time. The Project will complete the application for a Title V operating permit after start-up of the facility.

4.4.5 s. NR 410 – Air Permit, Emission, and Inspection Fees

This section describes the fees necessary for submitting a permit to WDNR for processing. The Project has included the necessary permit fees as indicated in s. NR 410.03.

4.4.6 s. NR 415 – Control of Particulate Emissions

This section applies to all air contaminant sources which emit particulate matter and to their owners and operators. The general limitations (s. NR 415.03) contained in this regulation state, "No person may cause, allow or permit particulate matter to be emitted into the ambient air which substantially contributes to exceeding of an air standard, or creates air pollution."

NR 415.04 addresses fugitive dust and states, "No person may cause, allow or permit any materials to be handled, transported or stored without taking precautions to prevent particulate matter from becoming airborne. Nor may a person allow a structure, a parking lot, or a road to be used, constructed, altered, repaired, sand blasted or demolished without taking such precautions...Such precautions shall include, but not be limited to...[t]he paving or maintenance of roadway areas so as not to create air pollution."

All roads will be paved, thus meeting the requirements of this rule.

Section NR 415.05 more specifically provides: "No person may cause, allow or permit the emission of particulate matter to the ambient air from any indirect heat exchanger, power or heating plant, fuel-burning installation or pulp recovery furnace with maximum heat input more than one million Btu per hour in excess of one of the listed limitations."

The limits applicable to the Project are as follows:

- The auxiliary boiler, two gas heaters, fire pump, and diesel generator are all limited to 0.15 lb PM/MMBtu per NR 415.06(2)(a)
- The combustion turbine is limited to 0.10 lb PM/MMBtu per NR 415.06(2)(c)

4.4.7 s. NR 417 – Control of Sulfur Emissions

This chapter applies to all air contaminant sources which emit SO_2 or other sulfur compounds and to their owners and operators. Section NR 417.03 provides: "No person may cause, allow or permit emission of sulfur or sulfur compounds into the ambient air which substantially contribute to the exceeding of an air standard or cause air pollution." However, there are no specific limits for natural gas-fired and ultra-low sulfur fuel oil-fired equipment.

4.4.8 s. NR 419 – Control of Organic Compound Emissions

This chapter applies to all air contaminant sources which emit organic compounds and to their owners and operators. "No person may cause, allow or permit organic compound emissions into the ambient air which substantially contribute to the exceeding of an air standard or cause air pollution," s. NR 419.03(1). However, there are no specific limits for any new equipment for this Project.

4.4.9 s. NR 420 – Control of Organic Compound Emissions from Petroleum and Gasoline Sources

This regulation lists the storage, recordkeeping, and maintenance requirements for organic compound storage tanks larger than 40,000 gallons. However, the 180,000-gallon storage tank at the facility will be exempt from the rules in this section under NR 420.03(1)(a) – exemption for storage vessels being used for number 2 through number 6 fuel oils.

4.4.10 s. NR 426 – Control of Carbon Monoxide Emissions

This regulation restricts any source from emitting CO in quantities or amounts that cause or contribute to an exceedance of air quality standards or cause air pollution. The air dispersion modeling performed as part of this application and detailed in Part 6 of this report demonstrates that this facility will not cause or contribute to a violation of any CO air quality standards.

4.4.11 s. NR 427 – Control of Lead Emissions

This chapter applies to all air contaminant sources which emit lead and to their owners and operators. However, no specific limits apply to the equipment for this Project.

4.4.12 s. NR 428 – Control of Nitrogen Compound Emissions

This chapter applies to all air contaminant sources which emit nitrogen compounds and to their owners and operators. However, no specific limits apply to the equipment for this Project.

4.4.13 s. NR 429 – Malodorous Emissions and Open Burning

This regulation is intended to restrict offensive odors in the ambient air and the burning of refuse, except under certain conditions, and would apply to the facility.

4.4.14 s. NR 431 – Control of Visible Emissions

No person may cause, allow, or permit emissions into the ambient air from any direct or portable source in excess of one of the limits specified in this chapter. The combustion turbine, auxiliary boiler, two gas heaters, fire pump, and diesel generator are limited to 20 percent opacity. Where the presence of uncombined water is the only reason for failure to meet the requirements of this chapter, such failure is not a violation of this chapter.

4.4.15 s. NR 432 – Allocation of Clean Air Interstate Rule NO_x Allowances.

This rule adopts the federal Clean Air Interstate Rule (CAIR) into the state rules. To address interstate transport of pollutants, it contains state regulations regarding NO_x reductions from major electric generating units in Wisconsin. Please note, this rule has been replaced by the Cross-State Air Pollution Rule.

4.4.16 s. NR 436 - Emission Prohibition, Exceptions, Delayed Compliance Orders and Variances

This requirement prohibits emissions into the ambient air in excess of limitations set under s. NR 400 through 499. As indicated within this application, emission limits for the Project will be at least as stringent as those established under ss. NR 400 through 499. However, the WDNR may grant exceptions to the emission limits pursuant to WDNR-approved plans.

4.4.17 s. NR 438 - Air Contaminant Emission Inventory Reporting Requirements

The WDNR has established specific requirements applicable to all air contaminant sources to demonstrate compliance with permit requirements. This application incorporates these requirements, and the Project will be subject to these requirements as they are included in the construction and operating permits. The Owners would submit an Emissions Inventory Report annually to the WDNR, along with necessary emission fees.

4.4.18 s. NR 439 - Reporting, Recordkeeping, Testing, Inspection and Determination of Compliance Requirements

The WDNR has established specific requirements applicable to emission sources to demonstrate compliance with permit requirements. This application incorporates these requirements, and the Project will be subject to these requirements as they are included in the construction and operating permits.

4.4.19 s. NR 440 - Standards of Performance for New Stationary Sources

Wisconsin has incorporated some of the NSPS listed in 40 CFR Part 60 into the state regulations. This is a review of those regulations with respect to the Project. Although the State of Wisconsin has adopted the federal NSPS, the Wisconsin rules may not be updated as soon as the federal rules. Where this is the case, the more restrictive federal standards apply. Applicable NSPS are addressed above in Section 4.2.

4.4.20 s. NR 445 - Control of Hazardous Pollutants

Sources that combust a group 1 virgin fossil fuel are exempt from NR 445 requirements per 445.07(5)(a). Accordingly, no NR 445.07 analysis is included for the following Project emission sources:

- EU01 – Combustion Turbine (Stack S01)
- EU02 – Auxiliary Boiler (Stack S02)
- EU04 – Natural Gas Heater #1 (Stack S04)
- EU05 – Natural Gas Heater #2 (Stack S05)
- EU06 – Emergency Diesel Fire Pump (Stack S06)
- EU07 – Emergency Diesel Generator (Stack S07)

The following emission units do not emit any pollutants that are regulated under NR 445:

- F03 – SF6 Circuit Breakers
- F01 – Haul Road Fugitives

The following emission units emit pollutants that are regulated under NR 445:

- Process P01, Stack S01, Control C01a - SCR
- EU08 – Diesel Tank (Stack S08)
- EU09 – Diesel Generator Tank (Stack S09)
- EU10 – Diesel Fire Pump Tank (Stack S10)
- F02 – Natural Gas and Fuel Oil Piping Components

The total non-exempt potential emissions of HAPs from the Project are summarized in Appendix C for the most significant state HAPs emitted from the Project.

The exhausts from the tanks are considered to be obstructed for the purposes of NR 445 because the breathing vents for these storage tanks are not powered exhausts. As such, the potential HAP emissions resulting from these emission units have been multiplied by a factor of 4. For conservativeness, each non-exempt HAP was assumed to be equal to the full estimated breathing and loading VOC losses from the EPA TANKS emission software (emissions were not speciated).

The natural gas and fuel oil piping components are considered fugitive emissions and have been multiplied by a factor of 4.

The total non-exempt potential emissions of HAPs from the Project are summarized in Appendix C. The table also lists the thresholds for each HAP for each stack height category. When comparing the total non-exempt potential emission rate for each HAP to the corresponding NR 445 threshold values, the threshold values will not be exceeded for any of the listed HAPs, except for the ammonia 24-hour average.

The SCR will have a maximum ammonia slip level of 10 ppm which yields an emission rate of 62.0 pounds per hour (lb/hr) (543,120 pounds per year [lb/yr]). The NR 445 threshold for a stack greater than 75 feet in height is 28.2 lb/hr and 612,587 lb/yr; therefore, dispersion modeling is required for the 24-hr average. The 24-hour ambient air standard in NR 445 for ammonia is 418 micrograms per cubic meter ($\mu g/m^3$). The resultant modeled concentrations are shown in Table 4-2 and show compliance with the ambient air standard.

Table 4-2: NR 445 Air Dispersion Modeling Results for 24-hour Ammonia Concentration

Pollutant	Maximum Modeled Impact	NR 445 Air Quality Standard
	micrograms per cubic meter ($\mu g/m^3$)	
Ammonia	16.5	418

Based upon this analysis, the Project will be in compliance with the requirements of NR 445.

4.5 Chemical Accident Prevention

40 CFR Part 68, Accidental Release Prevention Provisions, under Clean Air Act (CAA) Section 112(r), Prevention of Accidental Releases, establishes a general duty for owners and operators of stationary sources who produce, process, handle, or store any of a number of regulated substances, to prevent and

mitigate accidental releases of these substances by preparing detailed risk assessments and implementing a number of safety procedures through the preparation of a risk management plan (RMP).

The specific requirements of the RMP for affected facilities are established in 40 CFR Part 68, Accidental Release Prevention Provisions. These regulations require the owner or operator of an affected source to prepare and implement an RMP to detect and prevent or minimize accidental releases of regulated substances, and to provide a prompt emergency response to any such release to protect human health and the environment.

Affected facilities are those stationary sources that store, use, or handle any of the 140 listed hazardous chemicals or flammable/explosive substances in amounts greater than the listed threshold quantities. This list of regulated substances includes commonly stored liquid phases of gases such as ammonia, which the Project may store at quantities near or above the threshold levels for use in conjunction with the SCR for NO_x control on the combustion turbine. If a facility stores aqueous ammonia of concentrations of 20 percent or greater an RMP is required for the facility’s storage, use, and handling of ammonia.

Aqueous ammonia (19 percent solution) will be delivered to the site via a truck with an unloading pump then stored in a bulk 35,000-gallon storage tank. The Project’s SCR would use 19 percent concentration aqueous ammonia, therefore, an RMP is **not required** for the facility’s storage, use, and handling of ammonia.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

S. NR 405, WAC requires the application of BACT for each regulated NSR pollutant for which a significant net emissions increase will be realized as a result of the Project. As indicated in Part 1, the Project will result in significant emission increases of NO_x, CO, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4 mist, and CO_2e for combined-cycle operation. These pollutants will be subject to PSD review. Additionally, WDNR requires a BACT for opacity. Therefore, a BACT analysis was performed for each of these regulated NSR pollutants.

The Project will consist of one H-Class combustion turbine with a HRSG and one steam turbine in a combined-cycle configuration and associated support equipment. The combustion turbine will be designed to utilize pipeline-quality natural gas and combust fuel oil (ultra-low sulfur diesel) as back-up fuel. In addition to the combustion turbine, an auxiliary boiler, circuit breakers, two natural gas-fired gas heaters (natural gas heater), an emergency diesel fire pump, an emergency diesel generator, fuel oil storage tanks, haul roads, and natural gas and fuel oil piping components will be included as part of the Project. This Part describes the BACT analysis for all new equipment proposed for the Project.

The BACT analysis was performed using the “top-down” approach, which is described in this Part. A summary of the BACT emission limits and the associated control technologies for the combined-cycle combustion turbine are shown in Table 5-1. BACT emission limits and associated control technologies for the auxiliary equipment are listed in Table 5-2.

Table 5-1: Summary of BACT Results: Combined-Cycle Operation

Pollutant	Fuel	Control	BACT Emissions[a,b]	Average
NO_x	Natural gas	Selective catalytic reduction (SCR) and low-NO_x burners	2 ppm (with or without duct firing)	24-hour rolling
	Fuel oil	SCR and water injection	6 ppm (with or without duct firing)	24-hour rolling
CO	Natural gas	Good combustion practices, oxidation catalyst	1.5 ppm (with or without duct firing)[c]	168-hour rolling
	Fuel oil	Good combustion practices, oxidation catalyst	1.5 ppm (with or without duct firing)[c]	168-hour rolling
PM/PM_{10}/ $PM_{2.5}$	Natural gas	Combustion controls and low ash fuels	36.3 lb/hr (with duct firing) 21.8 lb/hr (without duct firing)	NA
	Fuel oil	Combustion controls and low ash fuels	54.5 lb/hr (with duct firing) 39.4 lb/hr (without duct firing)	NA
VOC	Natural gas	Good combustion practices, oxidation catalyst	2.7 ppm (with duct firing) 0.6 ppm (without duct firing)	168-hour rolling
	Fuel oil	Good combustion practices, oxidation catalyst	3.3 ppm (with duct firing) 0.6 ppm (without duct firing)	168-hour rolling
H_2SO_4 mist	Natural gas	Combustion controls and low sulfur fuels	9.9 lb/hr (with duct firing) 7.8 lb/hr (without duct firing)	NA
	Fuel oil	Combustion controls and low sulfur fuels	9.3 lb/hr (with duct firing) 7.0 lb/hr (without duct firing)	NA
Greenhouse gases	Natural gas	Use of natural gas as a fuel, monitoring and control of excess air, efficient turbine design, and oxidation catalyst	850 lb CO_2/MW-hr, gross	12-month rolling
	Fuel oil	Use of ultra-low sulfur diesel as a fuel, monitoring and control of excess air, efficient turbine design, and oxidation catalyst	1,180 lb CO_2/MW-hr, gross	12-month rolling
Opacity	Both	Low-NO_x burners, SCR, combustion controls, low ash fuels	N/A	N/A

Source: Construction permit no.: 18-MMC-168
(a) ppm = parts per million; lb/hr = pounds per hour; lb/MW-hr = pound per megawatt hour
(b) Concentration at 15 percent oxygen while operating at MECL and greater under steady state conditions, unless otherwise noted
(c) Natural gas limit valid for 100% load with duct firing down to MECL. Fuel oil limit valid for 100% load with duct firing down to 75% load.

Table 5-2: Summary of BACT Results: Auxiliary Equipment

Equipment	Pollutant	Control[a]	BACT Emission Rate[a]
Auxiliary boiler - B02	NO_x	Ultra-LNB/GCP/clean fuels/FGR	0.011 lb/MMBtu
	CO	Oxidation Catalyst/GCP/clean fuels	0.0037 lb/MMBtu
	$PM/PM_{10}/PM_{2.5}$	GCP/clean fuels	0.01 lb/MMBtu
	VOC	Oxidation Catalyst/GCP/clean fuels	0.0027 lb/MMBtu
	H_2SO_4 mist	GCP/clean fuels	0.01 lb/hr
	Greenhouse gases (CO_2e)	GCP/clean fuels	160 lb/MMBtu
	Opacity	GCP/clean fuels	N/A
Circuit Breaker – F03	SF_6	Leak monitoring	<0.5% loss rate
Natural gas heaters -P04 and P05 (each)	NO_x	LNB/GCP/clean fuels	0.049 lb/MMBtu
	CO	GCP/clean fuels	0.08 lb/MMBtu
	$PM/PM_{10}/PM_{2.5}$	GCP/clean fuels	0.01 lb/MMBtu
	VOC	GCP/clean fuels	0.005 lb/MMBtu
	H_2SO_4 mist	GCP/clean fuels	NA
	Greenhouse gases (CO_2e)	GCP/clean fuels	NA
	Opacity	GCP/clean fuels	N/A
Emergency diesel fire pump – P06	NO_x	GCP/clean fuels	3.0 g/hp-hr
	CO	GCP/clean fuels	2.6 g/hp-hr
	$PM/PM_{10}/PM_{2.5}$	GCP/clean fuels	0.15 g/hp-hr
	VOC	GCP/clean fuels	1.1 g/hp-hr
	H_2SO_4 mist	GCP/clean fuels	NA
	Greenhouse gases (CO_2e)	GCP/clean fuels	NA
	Opacity	GCP/clean fuels	N/A
Emergency diesel generator – P07	NO_x	GCP/clean fuels	4.8 g/hp-hr
	CO	GCP/clean fuels	2.6 g/hp-hr
	$PM/PM_{10}/PM_{2.5}$	GCP/clean fuels	0.15 g/hp-hr
	VOC	GCP/clean fuels	0.32 g/hp-hr
	H_2SO_4 mist	GCP/clean fuels	NA
	Greenhouse gases (CO_2e)	GCP/clean fuels	NA
	Opacity	GCP/clean fuels	NA
Diesel tanks – T01, T02, T03	VOC	Fixed roof tank	NA
Haul Roads – F01	$PM/PM_{10}/PM_{2.5}$	Haul roads	Fugitive Dust Control Plan
Natural gas and fuel oil piping components – F02	GHG	Fuel Piping	LDAR program - instrument monitoring
	VOC	Fuel Piping	

Source: Construction permit no.: 18-MMC-168 and 21-MMC-011
(a) FGR = flue gas recirculation; LNB = low-NO_x burners; GCP = good combustion practices; lb/MMBtu = pound per million British thermal units; tpy = tons per year; g/hp-hr = gram per horsepower hour

BACT is an emission limitation based on the maximum degree of reduction which the WDNR determines is achievable, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

The WDNR has directed by policy that the BACT be determined using a "top-down" process. The "top-down" process was outlined in a December 1, 1987, memorandum from the EPA Assistant Administrator for Air and Radiation.

While there is no legal requirement to perform the BACT analysis utilizing a specific criteria or process, the WDNR follows the EPA-developed guidance that establishes a five-step "top-down" BACT process/methodology (EPA, 1990).

For purposes of this PSD application, the Owners have prepared this BACT analysis consistent with EPA's top down approach, which consists of the following steps:

Step 1 – Identify all potential control technologies
Step 2 – Determine technical feasibility (of potential technologies)
Step 3 – Rank control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document results
Step 5 – Select BACT

Each of these steps is discussed in further detail below.

Step 1 – Identify all potential control technologies. The first step in a "top-down" analysis is to identify, for all applicable emission units, all "available" control options. Available control options are defined as those air pollution control technologies or techniques that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation and have been demonstrated in practice. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including innovative fuel combustion techniques and add-on controls.

Step 2 – Determine technical feasibility (of potential options). In the second step, the technical feasibility of the control options identified in Step 1 is evaluated with respect to source-specific factors. A demonstration of technical infeasibility should be documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 – Rank control technologies by control effectiveness. All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis.

Step 4 – Evaluate most effective controls and document results. After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are taken into account, in this Step. For each control option an objective evaluation of each impact is presented. Both beneficial and adverse impacts should be discussed and, where possible, quantified. If the Owners accept the top alternative in the listing as BACT, the Owners proceed to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis ends, and the results proposed as BACT. If the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding is documented and the next level of control is analyzed.

Step 5 – Select BACT. The final BACT determination is presented in this Step.

Greenhouse Gas BACT Process

Based on EPA Greenhouse Gas Guidance (EPA, 2011), the Greenhouse BACT process is similar to the five Steps summarized above. Steps 1 and 2 identify potential control strategies and then eliminate technologically infeasible options. Step 3 ranks the remaining technically feasible control technologies. Step 4 evaluates the most effective control technologies from an environmental, energy, and economic perspective. And finally, Step 5 selects the most appropriate BACT.

The BACT analysis for the Project is also based on the following concepts:

- Emission limits are defined on a “case-by-case” analysis that considers site specific factors
- Emission limits must be “achievable” on a long-term, day in and day out, basis
- The technology must be available and feasible for a specific project
- BACT does not redefine the facility as proposed (including fuels)

There is no prescriptive approach to performing a case-by-case control technology and emission limit analysis. PSD permitting authorities determine emission limits on a case-by-case basis. These case-by-case determinations must consider source-specific and site-specific characteristics. This is not a “cookiecutter" approach and there is no single right answer to determining the appropriate emission limits for a specific source or for a specific pollutant.

The WDNR is not required to set any emission limit at the most stringent level that has been demonstrated by a facility using similar emissions control technology. Similarly, an emission limit does not need to be set at the most stringent emission limit found in another permit. Rather, the WDNR has the authority and is required to evaluate and determine the correct emissions limits and control technologies for a project based on project-specific factors, including location. The case-by-case process does not require that each subsequent determination identify emission limitations that are equal to or more stringent than the previous determination.

Further, in establishing the emission limits, the BACT must confirm that emission limits are achievable by the specific facility that is subject to the emission limits: (1) over the life of the facility; and (2) during all operating conditions, not just ideal conditions. The use of a safety factor or margin is well-established in the air permitting context to appropriately account for the uncertainty and operational variability that will occur over the life of a facility. This safety factor must be sufficient to allow permit holders to comply on a continuous basis. Emission limits should not be based on the lowest emissions rate or highest control efficiency ever documented by a similar facility for a short-term period. The emission limits must account for a full range of operating conditions and the inherent variability of complex fuel combustion and air pollution control systems.

To be considered in the permitting process, a control technology must be commercially available (i.e., it must be offered for sale on a commercial scale through commercial channels). Permittees are not required to explore research and development projects to determine whether a specific technology is suitable. In addition, to be considered feasible technology for purposes of inclusion in an analysis, a particular technology must have been previously demonstrated, on a long-term basis, at commercial scale. In fact, even 2-3 years of operating history on a commercial scale has been determined to be insufficient to demonstrate that a particular technology is feasible.

The air permit process cannot redefine the source. The Owners have defined the "proposed facility," including the goals, objectives, purpose and basic design. Requiring alteration as to the type of power generating unit and/or range of fuels to be used would redefine the source.

Fuels can be an inherent part of a project design. In such cases, the air permitting process cannot be used to require a fuel other than the fuels proposed by the Owners. As Congress explained, "the Administrator may consider the use of clean fuels to meet BACT requirements <u>if a permit applicant proposes</u> to meet such requirements by using clean fuel. In no case is the Administrator compelled to require the mandatory use of clean fuels by a permit applicant." (emphasis added). S. Rep. No. 101-228 at 338 (1989).

The first step in the "top-down" BACT process is the identification of potentially available control technologies. One of the ways to identify available control technologies is to review previous BACT determinations for similar sources. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify recent BACT determinations for similar projects. This database is maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. Advanced queries of the database were conducted to identify control technology determinations for sources similar to the proposed combined-cycle combustion turbine and applicable auxiliary equipment. The queries are summarized in Table 5-3, below. The results of the RBLC query can be found in Appendix D.

Table 5-3: RBLC Query Information

Equipment	Process Type Lookup Code	Initial Look-up Dates	Addendum Look Up Dates
Combined-Cycle Combustion Turbine P01	15.210 – Natural gas combustion 15.220 – Fuel oil combustion	October 2008 to October 2018	November 2018 to October 2021
Auxiliary Boiler P02	13.310 – Natural Gas	October 2008 to October 2018	November 2018 to October 2021
Circuit Breakers F03	99.999 – Other Miscellaneous Sources	January 2010 to January 2020	February 2020 to October 2021
Natural gas heaters P04 and P05	13.310 – Natural Gas	October 2008 to October 2018	November 2018 to October 2021
Emergency diesel fire pump P06	17.210 – Fuel Oil	October 2008 to October 2018	November 2018 to October 2021
Emergency diesel generator P07	17.110 – Fuel Oil	October 2008 to October 2018	November 2018 to October 2021
Haul Roads F01	99.410 – Paved Roads	January 2010 to January 2020	February 2020 to October 2021
Natural gas and fuel oil piping component F02	64.002 – Equipment Leaks 50.007 – Petroleum Refining Equipment Leaks/Fugitive Emissions	January 2010 to January 2020	February 2020 to October 2021

To identify previous control technology determinations for comparable sources, queries were run using the "standard search" in which the RBLC database was searched using the following parameters:

- Draft Determinations and RBLC Permits issued during or after the dates presented in Table 5-3
- Standard Industrial Classification (SIC) code of 4911 for electrical generation plants

- North American Industrial Classification System (NAICS) code for a combustion turbine electrical generation plant 221112 which includes all types of fossil fuel electrical generation plants.
- SIC codes for auxiliary equipment, as applicable

The NAICS and SIC codes are the most appropriate codes to search in the advanced search option of the RBLC. The SIC and NAICS are systems of source classification developed for the purpose of differentiating industrial types. The SIC and the NAICS systems are used in many EPA documents to differentiate types of industries. It is appropriate to use these codes as the match criteria in queries of the RBLC database since other facilities that use similar turbines will likely have similar characteristics. After the NAICS and SIC codes were identified and queries run, combustion turbines that were not similar (e.g., digester gas-fired, fuel oil-fired, cogeneration units, boilers, etc.) were eliminated from the search. Information on turbine emissions was sorted from the remaining combustion turbine listing. A discussion of control options identified in the RBLC database is included in each subsection. When the combustion turbine results were found in a search, results for the various auxiliary equipment were also available in the search results as well. Therefore, complete RBLC searches were done for all BACT-eligible equipment.

In some cases, the RBLC listings are not clearly categorized and cover both simple- and combined-cycle installations. Also, it should be noted that all RBLC listings in California represent Lowest Achievable Emission Rate (LAER); although they are often listed as BACT, BACT and LAER are essentially the same in California. LAER is a much more stringent requirement than BACT and involves application of control technology regardless of cost. This is not the case for the proposed Project, which is subject only to BACT.

5.1 BACT for Nitrogen Oxides – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the nitrogen oxides BACT section for the combined-cycle combustion turbine are presented in Table 5-4. The updated combined-cycle combustion turbine nitrogen oxides BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-4: Combustion Turbine Nitrogen Oxides BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D, December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down steps for NO_x emissions from the combustion turbine.

5.1.1 Step 1. Identify All Potential Control Strategies

NO_x is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x)
2. The oxidation of nitrogen contained in the fuel (fuel NO_x)

Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all NO_x emissions from the combustion turbine will originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen and is exponential with peak flame temperature.

The combustion turbine will be subject to NO_x limits per NSPS Subpart KKKK and thus the BACT determination and resulting emission limits must be at least as stringent as the NSPS. During combined-cycle operation, the duct burners in the HRSGs will contribute to NO_x emissions. Part 4 identifies the applicable Subpart KKKK limits for the combustion turbine and duct burners.

Control of NO_x emissions from combustion turbines is generally aimed at either the prevention of NO_x formation or the capture and oxidation of post-combustion NO_x. Since the rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature, "front-end" control techniques are aimed at controlling one or more of these variables. These controls include the XONON^{TM} system and low-NO_x burners. The XONON^{TM} system uses a catalyst to keep the system temperatures lower while low-NO_x burners offer a staged combustion process, resulting in a lower peak flame temperature. Water injection reduces the combustion temperature, thereby reducing the formation of NO_x.

Other control methods utilize add-on control equipment to remove NO_x from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia into the gas stream to reduce the NO_x to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst (selective non-catalytic reduction [SNCR]) or with the use of a catalyst (SCR). Finally, EM_x^{TM} (formerly $SCONO_x^{TM}$), a multi-pollutant control technology, relies upon a catalyst similar to SCR to reduce NO_x emissions but does so without injecting ammonia into the exhaust gas stream.

The output from the RBLC search provided in Appendix D shows that a variety of emission limits and control technologies have been applied to combustion turbines for natural gas and fuel oil combustion. The most stringent limits found during a review of EPA's database were for facilities located in ozone non-attainment areas. These facilities were required to meet such low emission limits since they were subject to LAER requirements.

Typical BACT determinations for combined-cycle units that are located in attainment areas were in the 2 to 15 ppm range using low-NO_x burners, water injection, SCR, or a combination of these technologies. The lower emission rates listed utilize SCR.

5.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling NO_x emissions are evaluated for technical feasibility in the following sections.

5.1.2.1 XONON™ System

The XONON™ system controls NO_x emissions by preventing their formation. The key to the XONON™ system is the utilization of a chemical process versus a flame to combust fuel, thus limiting temperature and NO_x formation. The XONON™ system is an integral part of the combustor. The fuel and air that are supplied to the combustor are thoroughly mixed before entering the catalyst. The catalyst is responsible for combusting the fuel to release its energy. Due to the low catalyst operating temperatures, the nitrogen molecules are not involved in the reaction chemistry; they pass through the catalyst unchanged, thereby eliminating NO_x formation. The XONON™ system does have the same high outlet temperature, and some NO_x is formed in the post-combustion process. However, use of the technology has limited NO_x emissions to less than 2.5 ppm.

Currently, the XONON™ system has not had wide-scale application. It has been demonstrated on a 1.5-MW unit in California, with the unit operating in a base load capacity (24 hours a day, 7 days a week). Tests are underway to apply this technology to other types and sizes of turbines; however, testing data is currently unavailable. As the combustion turbine is expected to experience repeated start-ups and shutdowns, it is unclear how the changing load conditions would affect the XONON™ system. As this is a large combined-cycle project, and the XONON™ system has yet to demonstrate applicability for such units, **the XONON™ system has been deemed technically infeasible for this Project.**

5.1.2.2 EM$_x$™ System (formerly SCONO$_x$™)

The EM$_x$™ system (formerly SCONO$_x$™) uses a single catalyst to remove NO_x emissions from combustion exhaust gas by oxidizing nitric oxide to nitrogen dioxide (NO_2) and then absorbing the NO_2 onto a catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EM$_x$™ catalyst ranges from 300 ˚F to 700 ˚F. EM$_x$™ does not use ammonia. Therefore, there are no ammonia emissions from this technology.

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and nitrogen. CO_2 in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for EM$_x$™ is currently limited to combined-cycle combustion turbines under approximately 50 MW in size. The EM$_x$™ system has not been demonstrated on any type of combustion source other than a combustion turbine. There are technical differences between the proposed combustion turbine versus those few sources where this technology has been demonstrated in practice. In addition, this is a large combined-cycle project, and the EM$_x$ system has yet to demonstrate applicability for such units. Therefore, the EM$_x$ system has not been demonstrated to function efficiently on large combined-cycle combustion turbines and is not technically feasible. (Environmental Resource Management, 2014).

Therefore, EM$_x$™ is technically infeasible for this Project.

5.1.2.3 Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the HRSG have an exhaust temperature of approximately 200°F. Even strategically placing the ammonia injection further upstream would probably result only in peak temperatures of around 1,300°F. Such a low temperature would require that additional fuel be combusted at some point in order to raise the temperature to the levels that SNCR will operate. Combustion of the additional fuel would not only increase the NO_x emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

SNCR has not been applied to any combustion turbines according to the RBLC database. Because of the comparatively low exhaust temperatures, fuel and energy requirements, environmental implications and economic considerations; **SNCR is considered to be technically infeasible for the combustion turbine and duct burner under consideration for this Project.**

5.1.2.4 Selective Catalytic Reduction

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_x to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art control for combined-cycle back end gas turbine NO_x removal. SCR technology is being permitted as LAER and BACT for combined-cycle turbines at 2 to 5 ppm NO_x. Conventional SCR uses a metal honeycomb or “foil” catalyst support structure and requires an HRSG to drop flue gas temperatures to less than 600°F.

The Project's turbine will operate with the exhaust gases reaching temperatures over 1,100°F prior to entering the HRSG. Duct burner firing and passage of the flue gasses through the HRSG will lower the temperature of the gas stream to approximately 200°F. By placing the catalyst bed at the correct strategic point within the HRSG, an SCR could effectively operate and reduce NO_x emissions. A disadvantage of this system is that particles from the catalyst may become entrained in the exhaust stream and contribute to increased particulate matter emissions. In addition, ammonia slip reacts with the sulfur in the fuel creating ammonia bisulfates that become particulate matter. **SCR can be applied to the combined-cycle turbine and duct burner and is considered technically feasible.**

5.1.2.5 Low-NO_x Burners

Lean premixed combustors are currently available from most turbine manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing NO_x formation. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame-front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Controlled NO_x emission guarantees using low-NO_x burners range from 5 to 25 ppm for turbines 20 MW or greater but vary considerably from vendor to vendor without duct firing. With duct firing, these values vary depending on the size of the duct burners. **Low-NO_x burners are currently available for these turbines and duct burners and are a technically feasible control option for this Project for natural gas combustion.**

5.1.2.6 Water or Steam Injection

Steam and water injection work to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one.

Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent), but there is an increase in power output (typically 5 to 6 percent) due to the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection depending on the amount of water that is injected. Water injection is generally used for fuel oil combustion because it is difficult to aerosolize the fuel oil for air/fuel mixing or is used on aeroderivative combustion turbines. **Water/steam injection is available for the combined-cycle turbine and duct burner under consideration for this Project and is therefore considered technically feasible for fuel oil combustion.**

5.1.2.7 Summary of the Technically Feasible Control Options

Technically feasible NO_x control options for the combined-cycle combustion turbine are summarized in Table 5-5. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the combustion turbine.

Table 5-5: Summary of Technically Feasible NO_x Control Technologies for Combined-Cycle Combustion Turbines

Control System		Expected Performance (ppm)	Technical Feasibility	Comments
Combustion controls	Low-NO_x burners	35 (natural gas)	Feasible	Standard on combustion turbines for natural gas operation.
	Water injection	42 (fuel oil)	Feasible	Used only during fuel oil operation.
Post combustion controls	XONON™	N/A	Not feasible	Testing is still underway. Only used on a 1.5 MW unit not operating continuously.
	EM_x™	N/A	Not feasible	For units less than 50 MW in size
	Selective non-catalytic reduction	N/A	Not feasible	Exhaust temperature is too low.
	Selective catalytic reduction	2 (natural gas with or without duct firing) 6 (fuel oil with or without duct firing)	Feasible	2 ppm is the lowest achievable emission rate with SCR on natural gas. Catalyst will be fouled on fuel oil.

5.1.3 Step 3. Rank the Technically Feasible Control Technologies

Add-on controls may be used for natural gas and fuel oil combustion in the turbine. The combustion turbines under consideration come with low-NO_x burners and water injection as part of their standard packages; therefore, low-NO_x burners and water injection are used as the baseline for the proposed combustion turbine.

The technically feasible NO_x control technologies for the combustion turbine are ranked by control effectiveness in Table 5-6.

Table 5-6: Ranking of Technically Feasible NO_x Control Technologies for Combined-Cycle Combustion Turbines

Control Technology	Reduction (%)	Controlled Emission Level (ppm)[a]
Selective catalytic reduction	94-85%	2 ppm (natural gas) 6 ppm (fuel oil)
Low-NO_x burners	N/A (baseline for natural gas)	35 ppm
Water injection	N/A (baseline for fuel oil)	42 ppm

(a) Emission rate for 100% load to MECL with and without duct firing.

5.1.4 Step 4. Evaluate the Most Effective Controls

Recent BACT determinations have indicated a level of 2 to 15 ppm for NO_x emissions from combined-cycle units that are fired with natural gas (Appendix D). The combustion turbines under consideration are able to achieve 2 ppm while combusting natural gas and 6 ppm while combusting fuel oil on a long-term basis with SCR.

The Project's combined-cycle unit will have an SCR system located in the HRSG, along with low-NO_x burners and water injection which are standard on duel-fuel combustion turbines. The SCR vendors have indicated that 2 ppm is the lowest emission rate achievable with or without the duct burners operating for natural gas combustion. The SCR system will therefore be able to meet 2 ppm for all loads down to MECL, including when duct firing while combusting natural gas and 6 ppm while combusting fuel oil with and without duct firing. Because SCR represents the most effective control and has been selected as BACT, an economic feasibility determination is not required, per 40 CFR 52.21. The energy and environmental considerations for the selected BACT are discussed below for informational purposes.

SCR is selected as BACT for control of NO_x emissions from the proposed combined-cycle combustion turbine, along with low-NO_x burners (natural gas combustion) and water injection (fuel oil combustion).

5.1.4.1 Selective Catalytic Reduction

Energy Impacts

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions.

Environmental Impacts

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on a unit this size could be 10 ppm and may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. In addition, the storing of the ammonia on-site is another environmental and safety concern. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in designated landfills.

5.1.4.2 Low-NO_x Burners

Energy Impacts

Low-NO_x burners are usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). The increase in power output results from the increase in mass flow required to maintain turbine inlet temperature at manufacturer’s specifications. Because there is a power increase, no energy impacts are associated with low-NO_x burners.

Environmental Impacts

The low-NO_x burner system may increase CO and VOC emissions on a lb/hr basis; however, the potential increase in CO and VOC emissions does not outweigh the advantages of decreased NO_x emissions to reduce health effects.

Economic Impacts

The turbine manufacturer currently installs low-NO_x burners as standard equipment on natural gas-fired combustion turbines. With the low-NO_x burners, these turbines may achieve NO_x emission rates of 35 ppm at full load. Since the low-NO_x burners are considered standard equipment on the turbine, there is no annualized cost of the control.

5.1.4.3 Water Injection

<u>Energy Impacts</u>

Water injection, used during fuel oil operation only, is also usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). No huge energy impacts are associated with water injection.

<u>Environmental Impacts</u>

Water injection does use water, a natural resource, to control NO_x emissions. However, at the very few operating hours that are requested in this permit, the water use should be very minimal.

5.1.5 Step 5. Proposed NO_x BACT Determination

The BACT recommended for control of NO_x emissions from the combined-cycle combustion turbine is low-NO_x burners and water injection with SCR. These controls will meet a NO_x emission limit of 2 ppm at 15 percent oxygen during steady state conditions for all loads down to MECL with and without duct firing for natural gas combustion and 6 ppm at 15 percent oxygen during steady state conditions for all loads down to MECL with and without duct firing for fuel oil combustion. Compliance will be determined with NO_x CEMs on a 24-hour rolling average, excluding start-up and shutdown.

5.2 BACT for Carbon Monoxide – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the carbon monoxide BACT section for the combined-cycle combustion turbine is presented in Table 5-7. The updated combined-cycle combustion turbine carbon monoxide BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-7: Combustion Turbine Carbon Monoxide BACT Analysis References

<table>
<tr><th>Description</th><th>Previous Application Reference</th><th>December 2021
Submittal Location</th></tr>
<tr><td>BACT Analysis Steps 1 to 5</td><td>5.0 BACT
December 2018 Submittal</td><td>5.0 BACT</td></tr>
<tr><td rowspan="2">RBLC</td><td>Table D-1a (natural gas),
Table D-1b (fuel oil)
Appendix D, December 2018 Submittal</td><td>Table D-1a (natural gas),
Table D-1b (fuel oil)
Appendix D</td></tr>
<tr><td>--</td><td>Table D-1a Addendum (natural gas),
Table D-1b Addendum (fuel oil)
Appendix D</td></tr>
</table>

The following sections outline the top-down steps for CO emissions from combustion turbines.

5.2.1 Step 1. Identify Potential Control Strategies

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion control involves the use of catalytic oxidation; front-end control involves controlling the combustion process to suppress CO formation.

The technologies identified for reducing CO emissions from the Project’s turbine are the EM_x^{TM} system, an oxidation catalyst, and combustion controls. The standard technology for reducing CO emissions is to maintain “good combustion” through proper control and monitoring of the combustion process.

A survey of the RBLC database (Appendix D) indicated that most new combined-cycle turbines in attainment areas have been required to install add-on controls to control CO emissions from combined-cycle turbines. CO emissions from natural gas-fired combined-cycle turbines ranged from 0.9 to 25 ppm. H-class combustion turbines in combined-cycle mode have been permitted from 0.9 ppm to 5 ppm in most cases, based on the information that is available in the RBLC and from other sources that describe the class of turbines installed at the various locations. The lowest Siemens H-class permitted unit is 2.0 ppm.

5.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

5.2.2.1 EM_x^{TM} System

The EM_x^{TM} system was described in the BACT analysis for NO_x. The EM_x^{TM} system simultaneously oxidizes CO to CO_2, NO to NO_2, and then absorbs NO_2 onto the surface of a catalyst using a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. The system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EM_x^{TM} requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because EM_x^{TM} does not use ammonia there are no ammonia emissions from this technology.

Regeneration of the catalyst is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and nitrogen. CO_2 in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for EM_x^{TM} is currently limited to combined-cycle combustion turbines under approximately 50 MW in size. The EM_x^{TM} system has not been demonstrated on any type of combustion source other than a combustion turbine. There are technical differences between the proposed combustion turbine versus those few sources where this technology has been demonstrated in practice. These significant technical differences preclude a determination that the EM_x^{TM} system has been demonstrated to function efficiently on sources that are similar to the proposed furnaces and boilers (Environmental Resource Management, 2014).

Therefore, the EM_x^{TM} system is considered a technically infeasible method of controlling CO emissions from the proposed combined-cycle combustion turbine and duct burner.

5.2.2.2 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia with SCR, for a reaction to occur. The oxidation of CO to CO_2 utilizes excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities. It is expected that the catalyst will be placed in the exhaust train (HRSG) where the temperature will be optimal for the catalytic reaction.

The use of an oxidation catalyst is considered to be a technically feasible method of controlling CO emissions from the proposed combined-cycle combustion turbine and duct burner.

5.2.2.3 Combustion Control

"Good combustion practices" include operational and incinerator design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion. Such control practices applied to the proposed turbine can achieve CO emission levels of 4 ppm for the combustion turbine at 100 percent load.

Good combustion practices are considered to be a technically feasible method of controlling CO emissions from the proposed combined-cycle combustion turbine and duct burner.

5.2.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the CO control options for the proposed combined-cycle combustion turbine is summarized in Table 5-8. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

Table 5-8: Summary of Technically Feasible CO Control Technologies for Combined-Cycle Combustion Turbines

Control System		Expected Performance (ppm)[a]	Technical Feasibility	Comments
Combustion controls		4 (natural gas) 10 (fuel oil)	Feasible	Standard on turbines. Not an add-on control
Post combustion controls	Oxidation catalyst	1.5 (natural gas) 1.5 (fuel oil)	Feasible	Produces CO_2 emissions
	EM_x™	N/A	Not feasible	For units less than 50 MW in size

(a) Natural gas limit valid for 100% load with duct firing down to MECL. Fuel oil limit valid for 100% load with duct firing down to 75% load.

5.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the combustion turbine are ranked by control effectiveness in Table 5-9.

Table 5-9: Ranking of Technically Feasible CO Control Technologies for Combined-Cycle Combustion Turbines

Control Technology	Reduction (%)	Controlled Emission Level (ppm)[a]
Oxidation catalyst	50-80%	1.5 (natural gas) 1.5 (fuel oil)
Combustion control	Not applicable (baseline)	4 (natural gas) 10 (fuel oil)

(a) Natural gas limit valid for 100% load with duct firing down to MECL. Fuel oil limit valid for 100% load with duct firing down to 75% load.

5.2.4 Step 4. Evaluate the Most Effective Control Technologies

Operating the proposed combined-cycle combustion turbine with good combustion practices will achieve 1.5 ppm at 15 percent oxygen on a long-term basis for 100 percent load with duct firing down to MECL for natural gas combustion and 1.5 ppm at 15 percent oxygen for 100 percent load with duct firing down to 75 percent load for fuel oil combustion. The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

5.2.4.1 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Environmental Impacts

The oxidation catalyst oxidizes CO to CO_2 which is released to the atmosphere. CO_2 is a greenhouse gas that may be contributing to global warming and is now a regulated pollutant. Increasing CO_2 emissions could have a negative impact on the atmosphere. However, the oxidation catalyst will also reduce the amount of methane (CH_4) (also a greenhouse gas). Considering both greenhouse gases, the net effect is an overall decrease in greenhouse gas emissions on a CO_2e basis.

As with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; even if it is not hazardous, it adds to the already full landfills.

Economic Impacts

The Owners have selected the highest control available for CO emissions; therefore, no economic analysis is necessary.

The impacts listed above do not outweigh the health benefits of controlling CO emissions with the use of an oxidation catalyst.

An oxidation catalyst along with good combustion practices was selected as BACT for control of CO emissions from the combined-cycle combustion turbine.

5.2.5 Step 5. Proposed CO BACT Determination

The BACT recommended for control of CO emissions from the proposed combustion turbine is good combustion practices and the use of an oxidation catalyst. These controls will meet a CO emission limit of 1.5 ppm at 15 percent oxygen during steady state conditions for all loads down to MECL with and without duct firing for natural gas combustion and 1.5 ppm at 15 percent oxygen for 75 percent to 100 percent load with and without duct firing for fuel oil combustion. These proposed limits are on a 168-hour rolling average.

5.3 BACT for Particulate Matter – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the particulate matter BACT section for the combined-cycle combustion turbine is presented in Table 5-10. The updated combined-cycle combustion turbine particulate matter BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-10: Combustion Turbine Particulate Matter BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D, December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas), Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down steps for particulate matter emissions from combustion turbines.

5.3.1 Step 1. Identify Potential Control Strategies

Particulate ($PM/PM_{10}/PM_{2.5}$) emissions from natural gas combustion sources consist of inert contaminants in natural gas, of sulfates from fuel sulfur or mercaptans used as odorants, of dust drawn in from the ambient air, and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

A contributor to $PM/PM_{10}/PM_{2.5}$ emissions in combined-cycle turbines with SCR is the ammonium sulfates that are produced when NO_2 and ammonia react with sulfur in the fuel. Sulfur is present in all fuels, including natural gas and fuel oil proposed for this Project. Because of the sulfur, ammonium sulfates can form, as illustrated by the following equations:

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2\ HSO_4$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4\ HSO_4$$

Ammonium sulfates are also formed when the ammonia content of the flue gas exceeds that of the sulfur trioxide (SO_3); the amount of ammonium bisulfate then can increase as the ammonia slip increases. Other variables are velocity/temperature profiles, oxygen levels, water content, cycling, presence of an oxidation catalyst or duct burner, ammonia/SO_3 ratios, etc. Therefore, it is expected that combustion turbines with SCR will have higher particulate emissions than those without SCR.

Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas-fired turbines. Available control strategies include the use of low ash fuel, such as natural gas, and combustion controls. BACT emission rates vary in the RBLC database with rates being listed as 0.0012 to 0.044 lb/MMBtu and 4.4 to 43 lb/hr for natural gas and 0.0168 to 0.0368 lb/MMBtu and 34.3 to 72 lb/hr for fuel oil. As stated previously, these emission rates vary due to many reasons.

5.3.2 Step 2. Identify Technically Feasible Control Technologies

Particulate control devices are not typically installed on gas turbines. Post-combustion controls, such as ESPs or baghouses, have never been applied to commercial gas-fired turbines. Therefore, the use of ESPs and baghouse filters are both considered technically infeasible, and do not represent an available control technology.

In the absence of add-on controls, the most effective control method demonstrated for combustion turbines is the use of low ash fuel, such as natural gas, and combustion controls. This was confirmed by a survey of the RBLC database (Appendix D) which showed no add-on $PM/PM_{10}/PM_{2.5}$ control technologies for combined-cycle combustion turbine units. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

5.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies for the combustion turbine are ranked by control effectiveness in Table 5-11.

Table 5-11: Ranking of Technically Feasible $PM/PM_{10}/PM_{2.5}$ Control Technologies for Combined-Cycle Combustion Turbine

Control Technology	Reduction (%)	Controlled Emission Level (lb/hr)[a]
Low ash fuel and combustion control	Not applicable (baseline)	36.3 lb/hr (natural gas with duct firing) 21.8 lb/hr (natural gas) 54.5 lb/hr (fuel oil with duct firing) 39.4 lb/hr (fuel oil)

(a) Emission rate for 100% load to MECL with and without duct firing.

5.3.4 Step 4. Evaluate the Most Effective Control Technologies

No energy, environmental, or economic impacts are associated with combustion controls; the use of low ash fuel is not an add-on control device.

5.3.5 Step 5. Proposed $PM/PM_{10}/PM_{2.5}$ BACT Determination

The use of low ash fuels and good combustion control represents BACT for $PM/PM_{10}/PM_{2.5}$ control in the proposed combined-cycle combustion turbine. These operational controls will limit $PM/PM_{10}/PM_{2.5}$ emissions, including duct burner emissions, to the levels shown in Table 5-11, above, depending on fuel and operating condition for combined-cycle operation.

This limit includes front and back half $PM/PM_{10}/PM_{2.5}$ emissions, takes into account emissions from the ammonium sulfate produced from sulfur and ammonia slip that could be emitted as $PM/PM_{10}/PM_{2.5}$, and includes the duct burner emissions that will be emitted out of the turbine stack.

5.4 BACT for Volatile Organic Compounds – Combined-Cycle Combustion Turbine

Previously submitted BACT Sections and updated references to the VOC BACT section for the combined-cycle combustion turbine is presented in Table 5-12. The updated combined-cycle combustion turbine VOC BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-12: Combustion Turbine Sulfuric Acid Mist BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D, December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas), Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down steps for VOC emissions from combustion turbines.

5.4.1 Step 1. Identify Potential Control Strategies

Like CO, VOC is a product resulting from incomplete combustion. VOC emissions occur when a portion of the natural gas fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are unreacted trace constituents of the gas, while others may be products of the heavier hydrocarbon constituents. Partially burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion or incorrect air-to-fuel ratios in the combustion turbine.

The technologies identified for reducing VOC emissions from combined-cycle combustion turbines are the same as identified for CO control: the multi-pollutant control system, an oxidation catalyst (also referred to as a CO catalyst), and combustion controls. The standard technology for reducing VOC emissions is to maintain “good combustion” through proper control and monitoring of the combustion process through the air-to-fuel ratio. In addition, since most of the BACT determinations for CO for combined-cycle combustion turbines also include an oxidation catalyst, determinations for VOC emissions often include an oxidation catalyst along with good combustion practices. A survey of the RBLC database (Appendix D) indicates that combustion controls is the most prevalent BACT control along with oxidation catalysts listed as LAER and BACT for VOC. VOC emissions from the permitted facilities ranged from 0.3 ppm to 5 ppm for natural gas-fired combustion turbines and 2 ppm to 3.6 ppm for fuel-oil combustion.

5.4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

5.4.2.1 EM$_x$™ System

The EM$_x$™ system was described in the BACT analysis for NO_x (Section 5.1.2.2). It is also applicable for controlling VOC and can reduce emissions by up to 20 percent. The system does not use ammonia and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EM$_x$™ requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process. Because EM$_x$™ does not use ammonia, there are no ammonia emissions from this technology.

Regeneration of the catalyst is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and nitrogen. CO_2 in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for EM$_x$™ is currently limited to combined-cycle combustion turbines under approximately 50 MW in size. The EM$_x$™ system has not been demonstrated on any type of combustion source other than a combustion turbine. There are technical differences between the proposed combustion turbine versus those few sources where this technology has been demonstrated in practice. These significant technical differences preclude a determination that the EM$_x$™ system has been demonstrated to function efficiently on sources that are similar to the proposed furnaces and boilers (Environmental Resource Management, 2014).

Therefore, the EM$_x$™ system is considered a technically infeasible method of controlling VOC emissions from the proposed combined-cycle combustion turbines and duct burners.

5.4.2.2 Oxidation Catalyst

As discussed in Section 5.2.2.2, oxidation catalysts are a post-combustion technology that do not rely on the introduction of additional chemicals, such as ammonia or urea with SCR, for a reaction to occur. The catalyst beds that reduce CO also promote the oxidation of VOC, thereby reducing the VOC emissions out the stack. Such systems typically achieve a maximum of 35 to 40 percent removal of VOC, as opposed to the much higher efficiencies achieved for CO reduction.

The use of an oxidation catalyst for VOC control is considered to be technically feasible for the combined-cycle combustion turbine.

5.4.2.3 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion (controlling the air-to-fuel ratio). Such control practices applied to the proposed turbine can achieve VOC emission levels of approximately 1 ppm when combusting natural gas or fuel oil without an oxidation catalyst for all loads down to MECL.

Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed combustion turbine.

5.4.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the VOC control options for the proposed combustion turbine is summarized in Table 5-13. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbine.

Table 5-13: Summary of Technically Feasible VOC Control Technologies for Combined-Cycle Combustion Turbines

Control System		Expected Performance (ppm)	Technical Feasibility	Comments
Combustion controls		1 ppm (natural gas without duct firing) 1 ppm (fuel oil without duct firing)	Feasible	Standard on the proposed combustion turbine. Not an add-on control
Post combustion controls	Oxidation catalyst	2.7 ppm (natural gas with duct firing) 0.6 ppm (natural gas) 3.3 ppm (fuel oil with duct firing) 0.6 ppm (fuel oil)	Feasible	Produces CO_2 emissions.
	EM_x^{TM}	N/A	Not feasible	For units less than 50 MW in size

5.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the proposed combined-cycle combustion turbine are ranked by control effectiveness in Table 5-14.

Table 5-14: Ranking of Technically Feasible VOC Control Technologies for Combined-Cycle Combustion Turbines

Control Technology	Reduction (%)	Controlled Emission Level (ppm)[a]
Oxidation catalyst	35-40%	2.7 ppm (natural gas with duct firing) 0.6 ppm (natural gas) 3.3 ppm (fuel oil with duct firing) 0.6 ppm (fuel oil)
Combustion control	Not applicable (baseline)	4.1 ppm (natural gas with duct firing) 1 ppm (natural gas) 5.6 ppm (fuel oil with duct firing) 1 ppm (fuel oil)

(a) Emission rate for 100% load to MECL with and without duct firing.

5.4.4 Step 4. Evaluate the Most Effective Control Technologies

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

5.4.4.1 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create additional pressure drop, resulting in increased back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Environmental Impacts

The oxidation catalyst oxidizes CO and VOC to CO_2 which is released to the atmosphere. CO_2 is a greenhouse gas that may be contributing to global warming. Increasing CO_2 emissions could have a negative impact on the atmosphere.

In addition, as with all controls that utilize catalysts for pollutant removal, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; even if it is not hazardous, it adds to the existing landfills.

Economic Impacts

The Owners have selected the highest control available for VOC emissions; therefore, no economic analysis is necessary.

5.4.4.2 Combustion Control

No energy, environmental, or economic impacts are associated with combustion controls.

5.4.5 Step 5. Proposed VOC BACT Determination

The BACT recommended for control of VOC emissions from the proposed combustion turbine is the use of good combustion practices with the added control of an oxidation catalyst. These controls will meet a VOC natural gas combustion emission limit of 2.7 ppm at 15 percent oxygen and 0.6 ppm at 15 percent oxygen with and without duct firing, respectively for all steady state loads down to MECL. The controls will also meet a VOC fuel oil limit of 3.3 ppm at 15 percent oxygen and 0.6 ppm at 15 percent oxygen, with and without duct firing, respectively for all steady state loads down to MECL. These emission rates represent the lowest emission rate achievable for VOC emissions with an oxidation catalyst for this turbine. Compliance will be determined on a 168-hour rolling average.

An oxidation catalyst along with good combustion practices was selected as BACT for VOC emissions from the proposed combined-cycle combustion turbine for both fuel oil and natural gas combustion.

5.5 BACT for Sulfuric Acid Mist – Combined-Cycle Combustion Turbine

Previously submitted BACT Sections and updated references to the sulfuric acid mist BACT section for the combined-cycle combustion turbine is presented in Table 5-15. The updated combined-cycle combustion turbine sulfuric acid mist BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-15: Combustion Turbine Sulfuric Acid Mist BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D, December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas), Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down steps for H_2SO_4 mist emissions from combustion turbines.

5.5.1 Step 1. Identify Potential Control Strategies

The majority of the fuel sulfur combusted in the combustion turbine leaves the boiler as SO_2. During combustion, a small percentage of the fuel sulfur is further oxidized from SO_2 to SO_3. As the temperature of the flue gas decreases as it passes through the HRSG and pollution control systems, this SO_3 may combine with water vapor present in the exhaust gas path to form sulfuric acid vapor.

When the flue gas temperature drops below the acid dew point, sulfuric acid vapor further condenses into an aerosol, forming H_2SO_4 mist. H_2SO_4 mist may also be a component of condensable particulate matter, with particle sizes in the sub-micron size.

Very limited data is available on the quantity of SO_2 that will be converted to SO_3 through the entire combustion turbine/HRSG/SCR/oxidation catalyst. Vanadium is the component in SCR catalyst and is believed to catalyze the oxidation of SO_2 to SO_3 in the exhaust train when present in the fuel. No information on the amount of SO_2 that is oxidizes to SO_3 is available for oxidation catalyst. Therefore, the H_2SO_4 emission estimate assumes 100 percent conversion of SO_2 to SO_3 and 100 percent conversion of SO_3 to H_2SO_4, since no guarantees exist, and very little data is available for this combustion turbine with back-end controls. The combustion turbine will combust natural gas with sulfur content up to 0.5 grains per standard cubic foot on a 12-month rolling average, and fuel oil that will be less than or equal to 15 ppm sulfur (ultra-low sulfur fuel oil).

5.5.2 Step 2. Identify Technically Feasible Control Technologies

As with SO_2, there are no add-on controls available for H_2SO_4 mist from combustion turbines. In the absence of add-on controls, the most effective control method demonstrated for combustion turbines is the use of low sulfur fuel, such as natural gas and ultra-low sulfur fuel oil, and combustion controls. Proper combustion control and the firing of fuels with very low sulfur content is the only known control method available. This was confirmed by a survey of the RBLC database (Appendix D).

5.5.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible H_2SO_4 mist control technologies for the combustion turbine are ranked by control effectiveness in Table 5-16.

Table 5-16: Ranking of Technically Feasible H_2SO_4 Control Technologies for Combined-Cycle Combustion Turbines

Control Technology	Reduction (%)	Controlled Emission Level (lb/hr)[a]
Low sulfur fuel and combustion control	Not applicable (baseline)	9.9 lb/hr (natural gas with duct firing) 7.8 lb/hr (natural gas) 9.3 lb/hr (fuel oil with duct firing) 7.0 lb/hr (fuel oil)

(a) Emission rate for 100% load to MECL with and without duct firing.

5.5.4 Step 4. Evaluate the Most Effective Control Technologies

There are no energy, environmental, or economic impacts associated with combustion controls; the use of low sulfur fuel and combustion control is not an add-on control device.

5.5.5 Step 5. Proposed H_2SO_4 Mist BACT Determination

The use of low sulfur fuel and good combustion control represents BACT for H_2SO_4 mist control in the proposed combined-cycle combustion turbine. These operational controls will limit H_2SO_4 mist emissions, including duct burner emissions, to the levels shown in Table 5-16, above, depending on fuel and operating condition for combined-cycle operation.

5.6 BACT for Greenhouse Gases – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the greenhouse gases BACT section for the combined-cycle combustion turbine is presented in Table 5-17. The updated combined cycle combustion turbine greenhouse gas BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-17: Combustion Turbine Greenhouse Gases BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas), Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down steps for greenhouse gas (GHG) emissions from combustion turbines.

5.6.1 Step 1. Identify All Potential Control Strategies

For the proposed combined-cycle combustion turbine, the CO_2e emissions are due to CO_2, CH_4, and nitrogen oxide (N_2O) emissions. The GWP of CH_4 and N_2O emissions are normalized to the warming potential of carbon dioxide (as CO_2e) by multiplying the CH_4 emissions by 25 and the N_2O emissions by 298. Despite the higher warming potentials of CH_4 and N_2O compared to CO_2, it is expected that CO_2 emissions will still account for over 99 percent of the CO_2e GWP for this unit, based on published emission factors for natural gas-fired turbines.

There are two broad strategies for reducing CO_2 emissions from stationary combustion processes such as combustion turbines. The first is to minimize the production of CO_2 through the use of low-carbon fuels and through aggressive energy-efficient design. The use of gaseous fuels, such as natural gas, reduces the production of CO_2 during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly efficient operation requires less fuel for process heat, which directly impacts the amount of CO_2 produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce CO_2 production and the costs to recover it.

The second strategy for CO_2 emission reduction is carbon capture and sequestration. The inherent design of the combustion turbines produces a dilute CO_2 stream for potential capture.

The CO_2 emissions from combustion turbines can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO_2 exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing CO_2 from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains nearly 80 percent nitrogen, the CO_2 concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

5.6.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling GHG emissions are evaluated for technical feasibility in the following sections.

5.6.2.1 Fuel Selection

Fuel selection has a significant impact on GHG formation.

5.6.2.1.1 Low-Carbon Fuels

Numerous fuels are available for use. As Table 5-18 shows, combustion of natural gas yields 40 to 50 percent less CO_2 than does combustion of coal and petroleum coke and approximately 30 percent less CO_2 than does combustion of residual oil. Accordingly, the preferential burning of a low-carbon gaseous fuel in the proposed combustion turbine is an extremely effective CO_2 control technique. This control technique is technically feasible for the combustion turbine and duct burner and is an inherent part of the Project's design.

Table 5-18: CO_2 Emission Factors

Fuel	kilograms CO_2 per MMBtu
Petroleum coke	113.67
Coal (anthracite)	103.69
Distillate fuel oil No. 2	73.96
Natural gas	53.06

Source: Title 40 CFR Part 98: Table C-1 to Subpart C of Part 98 – Default CO_2 Emission Factors and Types of Fuel

5.6.2.1.2 Combustion of Biogenic Sources

The proposed combustion turbine has not been designed to accommodate fibrous biomass, such as woody biomass, which is the most likely biomass available in sufficient quantities for the unit from the surrounding area. For both regulatory and technical feasibility issues, **biogenic sources are not a feasible option since they are not part of the original design**.

5.6.2.2 Energy Efficiency

The evaluation of energy efficiency, continuous excess air monitoring and control and the selection of efficient turbine design, are discussed below.

5.6.2.2.1 Continuous Excess Air Monitoring and Control

Excessive amounts of combustion air in turbines results in energy-inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. This inefficiency can be alleviated using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, which reduces the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. Additionally, lowering excess air levels, while maintaining good combustion, reduces not only CO_2 emissions but also NO_x emissions. The combustion turbine will be equipped with oxygen monitors as part of the CEM system.

5.6.2.2.2 Selection of Efficient Turbine Design

Energy efficiency reduces CO_2 emissions by maximizing the operation of the combustion turbine, thereby reducing the amount of fuel burned per megawatt-hr produced.

Combustion control optimization and energy efficient equipment is a main control strategy for emissions of greenhouse gases. The combustion turbine design that is under consideration for this Project is highly efficient. Energy efficiency is technically and economically feasible. Potential options that may increase efficiency include the following:

- Airfoil-shaped compressor rotor blades designed to increase compressor efficiency
- 13 stage high efficiency compressor design with modulating inlet guide vanes and inter-stage air extraction for cooling and sealing air
- Fuel gas heating via HRSG feedwater to improve turbine efficiency while maintaining constant firing temperature
- Inlet air filtration system utilizing high efficiency media filters to remove combustion air contaminants
- On and off-line compressor water wash capability to remove deposits and other contaminants from compressor blades to maintain and improve compressor efficiency
- Low-NO_x combustor for improved performance, enhanced operability, and lower emissions
- Extended turndown for increased spinning reserve capability and lower fuel costs
- Advanced hot gas path components with 3D airfoil shapes, improved materials, improved sealing, more effective cooling to achieve increased turbine efficiency
- Higher firing temperatures to increase turbine performance and overall turbine efficiency

5.6.2.3 Add-on Control Devices

Another method of GHG control is an add-on control device.

5.6.2.3.1 Catalytic Oxidation

N_2O emissions are reduced by passing the combustion gases over a catalyst, converting N_2O to nitrogen plus oxygen. Similarly, VOC emissions, such as CH_4, may be converted from CH_4 to CO_2 plus water. For the same reasons given above in the discussion for CO BACT controls, **catalytic oxidation is technically feasible for the control of GHG emissions from the proposed combined-cycle combustion turbine.**

5.6.2.3.2 Thermal Oxidation

Several types of thermal oxidation technology are available. All these technologies oxidize CH_4 to CO_2 and water, by raising the temperature of the treated gas stream to approximately 1,600ºF for approximately one to two seconds. Given sufficient mixing, this residence time and temperature is capable of achieving at least a 98 percent reduction in CH_4 emissions for these processes.

Secondary pollutants, however, are produced by thermal oxidation, including NO_x and CO from the combustion of natural gas used to heat the process stream. Thermal oxidation technologies also may employ some form of heat recovery, either recuperative or regenerative, to reduce economic, environmental and energy costs. In the case of a combustion turbine, it is expected that approximately 20 lb/hr of CH_4 will be produced at full load (with an exhaust flow rate of approximately 1,000,000 million standard cubic feet per minute). The exhaust gas stream is thus both high volume and very dilute in CH_4, so it would need to be concentrated to the point that the CH_4 would be capable of combustion. Also, additional CO_2 would be produced due to the need for combusting natural gas to heat the CH_4 to the oxidation point. This would reduce the overall effectiveness in reducing CO_2e emissions due to CH_4 because additional CO_2 would be produced as a result of combusting the CH_4. **Therefore, thermal oxidation is technically infeasible for the control of GHG emissions from the proposed combined-cycle combustion turbine.**

5.6.2.4 Carbon Capture and Sequestration

Carbon capture and sequestration is a general term which is used for approaches that capture and separate CO_2 from an exhaust stream, and then store it in a place which will keep it from the atmosphere for a long time. The two general categories of CO_2 capture are: pre-combustion CO_2 capture and post-combustion CO_2 capture.

5.6.2.4.1 Pre-Combustion CO_2 Capture

Pre-combustion CO_2 capture is used in gasification plants, where the CO_2 is captured from the syngas prior to combustion in the turbine, where it is relatively concentrated in the gas stream. This facility is not a gasification plant; therefore, **pre-combustion capture is technically infeasible for the control of CO_2 emissions from the proposed combined-cycle combustion turbine**.

5.6.2.4.2 Post-Combustion CO_2 Capture

Post-combustion CO_2 capture is used for units such as pulverized coal plants. In these units, the flue gas concentration of CO_2 runs between 10-15 percent by volume and is released at atmospheric pressure. This results in a high actual volume of gas to be treated. Trace impurities in the airflow tend to reduce the effectiveness of the CO_2-adsorbing process and compressing the captured CO_2 from atmospheric pressure to pipeline pressure represents a large parasitic load. The currently available process is costly and energy intensive, so research is being done on ways to increase the solvent capture efficiency and reduce the cost. These approaches include investigating the use of alternative solvents, solid sorbents or membranes. Of these potentially more efficient approaches, most are currently at laboratory/bench scale, so are not technically feasible. Pilot scale processes are starting to be placed in service, such as a 48 MW slipstream project at Brindisi, Italy, started in March 2011, which is limited to capturing less than 10,000 tons of CO_2 per year. A larger 235-MW slipstream project for the 1,300 MW Mountaineer Power Plant near New Haven, West Virginia was built with technology that used chilled ammonia to trap CO_2. The pilot project removed up to 300,000 metric tons of CO_2; however, the project was abandoned due to diminishing Federal and State support for clean coal technology. No commercially available post-combustion CO_2 capture systems are known to have been installed at large power plant other than pilot-scale demonstration projects. Therefore, **post-combustion capture is technically infeasible for the control of CO_2 emissions from the proposed combined-cycle combustion turbine**.

5.6.2.5 CO_2 Sequestration

CO_2 sequestration involves transporting CO_2 to a suitable geologic location where it can be injected as a supercritical fluid into deep, underground rock formations for permanent storage. Identifying a suitable site within an economically-viable distance from the Project site will require site-specific quantitative risk assessment. Four trapping methods are known: mineral trapping, physical adsorption, hydrodynamic trapping, and solubility trapping.

5.6.2.5.1 Mineral Trapping

The mineral trapping method traps CO_2 by undergoing a chemical reaction with various minerals, resulting in the formation of a carbonate mineral. This process can be rapid or very slow, depending on the chemistry of the rock and water at the site. Mineral trapping is expected to result in the most stable, permanent form of geological CO_2 sequestration. Experiments have shown that basalt formations can rapidly transform injected CO_2 into carbonate minerals, beginning precipitation in a few months' time and completing conversion within 100 years or less, depending on depth of injection. Sandstone formations low in carbonates may also be suitable candidates, depending on the mineral contents of the formations. These methods have been demonstrated only on a laboratory scale; therefore, mineral trapping is **not technically feasible for the proposed combined-cycle combustion turbine**.

5.6.2.5.2 Physical Adsorption

The physical adsorption process traps CO_2 molecules are trapped in micropore wall surfaces of coal organic matter or organic rich shales. The hydrostatic pressure in the formation controls the adsorption process. The injection of CO_2 can also result in driving off CH_4 for collection by other wells, helping the economics. Wisconsin has coal beds in the mid-northeast part of the state (Northeast Wisconsin Shelf and Arkoma Basin). There is a commercial coal belt that contains coal beds greater than or equal to 10 inches thick. The coal beds that are greater than or equal to 14 inches thick are mineable by underground methods. Coal mining in Wisconsin has been steadily decreasing since 1981. Some coal beds in the US are being tested for CO_2 storage/ CH_4 recovery, but this is currently at a pilot phase. Defining the depths and lateral distribution of coal strata that might be suitable for this approach has not been done, due to the significant depths required for CO_2 sequestration. Significant research and exploration efforts would be required to determine whether such coal beds even actually occur at the required depths beneath western Wisconsin. Use of coal beds in Wisconsin would require much further study to locate a suitable site for sequestration, and since the results of pilot phase testing of this technique are not known, these factors combined render the use of coal beds **not technically feasible for the proposed combined-cycle combustion turbine.**

5.6.2.5.3 Hydrodynamic Trapping

With hydrodynamic trapping, the pore space of a salt-water aquifer takes the injected CO_2, in a geologic setting where the aquifer is capped by an impermeable rock layer to trap the CO_2 well below the near-surface environment. For storage purposes, the aquifer should be saline enough to be non-potable, and deep enough (over 2,700 feet) to confirm that the pressure is sufficient to keep the compressed CO_2 in a supercritical liquid phase. Since the sedimentary bedrock strata in the site vicinity are over 10,000 feet thick, the possibility exists that geologically suitable strata exist somewhere within these layered rock formations. However, in the absence of oil and gas exploratory test holes, the locations, depths, and character of such strata are not known, and would have to be discovered and defined by extensive exploratory drilling and testing. As the state of Wisconsin is unlikely to apply for primacy for the Class VI regulations (governing injection wells), EPA rules that require a minimum of 10,000 milligrams per liter (mg/L) total dissolved solids to qualify as saline enough to be suitable for injection will probably apply. Discovering locations which exceed 10,000 mg/L would require significant exploration and test wells to characterize the site and determine the aquifer suitability. At these depths, defining suitable geologic would be rendered costly and problematic. Multiple oil and gas fields exist in the region, but a serious limitation to feasibility in an existing oil or gas field is the great likelihood of significant numbers of "penetrations" (old, either documented or undocumented wells and test holes that may or may not be adequately plugged and abandoned). Also, the additional surface infrastructure that would be needed to inject CO_2 would be massive, problematic, and likely infeasible. Pilot-scale projects injecting CO_2 into saline aquifers are underway in Illinois and Texas at depths of over 6,000 feet and these are the closest known sites that have been initially characterized for potential long-term sequestration, but the studies are in their early stages. Therefore, hydrodynamic trapping is **technically infeasible for the control of CO_2 emissions from the proposed combined-cycle combustion turbine** at this time.

5.6.2.5.4 Solubility Trapping

With solubility trapping, the CO_2 dissolves in the water or forms carbonic acid, becoming slightly heavier and, theoretically, sinking to the bottom of the aquifer. Solubility trapping also occurs during CO_2 flooding for enhanced oil recovery (EOR). In this case, the CO_2 dissolves into the oil, and is trapped by the immobile, non-recoverable oil. CO_2 flooding has been used for years for EOR, resulting in some existing injection infrastructure at oil fields (using both solubility trapping and hydrodynamic trapping), although the sequestration effects were not originally monitored, and the volumes injected for such operations are minuscule. However, oil fields have stored crude oil and natural gas for millions of years, and the geologic conditions that trap oil and gas are also the conditions suitable for CO_2 storage. If the CO_2 is used for EOR, the cost of transporting it to the oil field may be partially offset. Since the sedimentary bedrock strata in the site vicinity are over 10,000 feet thick, the possibility exists that oil and gas fields involving geologically suitable strata exist somewhere within these layered rock formations within the region. However, defining suitable geologic conditions in an existing oil or gas field, including the locations, depths, and character of such strata would have to be defined by extensive exploratory drilling and testing. Multiple oil and gas fields exist in the region, however, as was the case with hydrodynamic trapping, there is a likelihood of undocumented penetrations. Also, additional surface infrastructure that would be needed to inject CO_2.would be massive, problematic, and likely infeasible. Therefore, solubility trapping is **technically infeasible for the control of CO_2 emissions from the proposed combined-cycle combustion turbine** at this time.

5.6.2.5.5 Summary of CO_2 Sequestration

To summarize, existing CO_2 capture technologies have not been applied at large power plants, as the economic costs are prohibitive, and while more efficient approaches are being investigated, none have currently been developed past the pilot-stage. A published cost estimate for a 235-MW slipstream pilot project in West Virginia is $668 million, so scaling that linearly to a size capable of handling the approximate 625-net MW capacity of this project would be over $1.8 billion. Potential carbon sequestration sites may exist in Wisconsin, but the technologies to use them are mostly still in the pilot-scale phase of development, and the Owners would need to do much more investigation in order to discover where the sites are, if any, and characterize them enough to demonstrate the long-term viability of the locations. Defining suitable geologic conditions in an existing oil or gas field, including the locations, depths, and character of suitable strata, and defining penetrations (potentially leaky wells and test holes, some of which are likely to exist but are undocumented) into the geological traps comprising existing oil and gas fields, would have to be defined by extensive exploratory drilling and testing. One of the closest known existing sites for sequestration is the Williston Basin in the Dakotas, approximately 350 miles from the plant. The cost to construct a pipeline as determined from a similar project (Iowa Power & Light Ottumwa – Iowa Department of Natural Resources project 11-219) to this project's site would be approximately $1.4 million/mile of pipeline, or about $700 million. The capital cost estimated for this comparable project was nearly $2.1 billion for capture equipment and pipeline construction alone prior to any costs for gas compression, additional injection and monitoring wells necessary to handle the volume of CO_2 produced, pipeline right-of-way, operation and maintenance costs, etc. As can be seen from the above discussion, the qualitative cost estimate of capture and sequestration is quite high, the technological effectiveness for the capture equipment for a unit of this size has not been demonstrated in practice yet, and there is uncertainty as to whether locations capable of storing the large amounts of CO_2 that would be produced per year exist within a closer radius of the plant. These considerations are sufficient to eliminate this option without requiring a more detailed site-specific technological or economic analysis.

5.6.2.6 Summary of Technically Feasible Control Technologies

The technical feasibility of the greenhouse gas control options for the proposed combustion turbine is summarized in Table 5-19. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbine.

Table 5-19: Summary of Technically Feasible Greenhouse Gas Control Technologies for Combustion Turbine

Control System		Technical Feasibility	Comments
Fuel Selection	Low Carbon Fuels	Feasible	Natural gas has been selected as the primary fuel for this project
	Combustion of Biogenic Sources	Not Feasible	--
Energy Efficiency	Continuous Excess Air Monitoring and Control	Feasible	Standard for the turbines under consideration
	Efficient Turbine Design	Feasible	Standard for the turbines under consideration
Post Combustion Controls	Catalytic Oxidation	Feasible	Will reduce CH_4 emissions but create CO_2
	Thermal Oxidation	Not Feasible	--
Carbon Capture	Pre-combustion CO_2 capture	Not Feasible	--
	Post-combustion CO_2 capture	Not Feasible	--
Carbon Sequestration	Mineral Trapping	Not Feasible	--
	Physical Adsorption	Not Feasible	--
	Hydrodynamic Trapping	Not Feasible	--
	Solubility Trapping	Not Feasible	--

5.6.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible control technologies are low-carbon fuel (natural gas), monitoring and control of excess air, efficient turbine design, and catalytic oxidation. The use of low-carbon fuels and aggressive energy-efficient design to reduce CO_2 emissions is inherent in the design of the proposed combustion turbine under consideration and is considered the baseline condition. Table 5-20 presents the ranking of the greenhouse gas technologies deemed feasible for the Project. While these four technologies are “ranked” in order of their presentation, they are more appropriately considered as a suite of measures that would be implemented to allow the Project to generate and consume power in the most efficient manner and thereby achieve BACT for greenhouse gases.

Table 5-20: Greenhouse Gas Control Technology Ranking for the Combustion Turbine

Technology	Ranking	Applied to Project
Combined – Cycle Combustion Turbine (employing efficient, state-of-the-art design)	1	Yes
Clean Fuel – Natural Gas	2	Yes
Catalytic Oxidation	3	Yes
Operational Design – Control of Excess Air	4	Yes

5.6.4 Step 4. Evaluate the Most Effective Control Technologies

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

5.6.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because the Owners are proposing to utilize all four of the feasible technologies for reducing greenhouse gases from the proposed combustion turbine, no detailed analysis is provided to compare the available control technologies' relative environmental, energy and economic impacts.

5.6.4.2 Oxidation Catalyst

An oxidation catalyst works to reduce CH_4 emissions according the following equation:

$$CH_4 + 2O_2 = CO_2 + 2H_2O$$

Substituting in the molecular weights of CH_4 (16.043 pound per pound mol [lb/lb-mol]) and CO_2 (44.0096 lb/lb-mol), the removal of 1 pound of CH_4 results in the release of 2.7 pounds of CO_2. However, CH_4 has a GWP of 25, whereas the GWP of CO_2 is 1. Substituting in the GWPs, the removal of 1 pound of CH_4 results in a net reduction of 22.3 lb CO_2 as CO_2e.

It is also important to note the increase in CO_2e emissions from the oxidation of CO to CO_2 in accordance with the following reaction:

$$2CO + O_2 = 2CO_2$$

CO_2 will be emitted at a rate of approximately 1.5 pounds per pound of CO. Therefore, it is expected that there will still be a net decrease in CO_2e, even with the additional CO_2 that is produced from the oxidation catalyst with the oxidation of CO and CH_4.

There are no additional negative environmental impacts from the use of an oxidation catalyst, other than those mentioned in Step 4 of the combustion turbine CO BACT.

5.6.5 Step 5. Proposed Greenhouse Gas BACT Determination

BACT for greenhouse gas emissions from the combustion turbine is determined to be the use of natural gas as a fuel, monitoring and control of excess air, efficient turbine design, and an oxidation catalyst. These design options will allow the combustion turbine to not exceed 850 lb CO_2/MW-hr (gross) on a 12-month rolling average basis while combusting natural gas and 1,180 lb CO_2/MW-hr (gross) on 12-month rolling average basis while combusting fuel oil.

5.7 BACT for Start-Up and Shutdown Emissions – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the BACT analysis sections for the start-up and shutdown emissions for the combined-cycle combustion turbine are presented in Table 5-21. The updated combined cycle combustion turbine start-up and shutdown BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-21: Combustion Turbine Start-Up and Shutdown BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1c (startup/shutdown) Appendix D, December 2018 Submittal	Table D-1c (startup/shutdown) Appendix D
	--	Table D-1c Addendum (startup/shutdown) Appendix D

The following sections outline the top-down BACT steps for start-up and shutdown emissions from the combustion turbine.

5.7.1 Step 1. Identify Potential Control Strategies

Criteria pollutants will be emitted during start-up and shutdown of the combustion turbine. Start-up emissions are generally higher for CO, NO_x, and VOC than for normal operation because the SCR and oxidation catalyst cannot fully operate to their full potentials until the exhaust gases reaches the appropriate operating temperature.

The Owners are requesting an hours per year limit on start-up and shutdown (1,525 hours per year for start-up and shutdown, combined) for natural gas operation and 42 start-ups and 42 shutdowns per year for fuel oil operation. Start-up is defined as 0 percent load to MECL and shutdown is defined as MECL to 0 percent load.

5.7.2 Step 2. Identify Technically Feasible Control Technologies

Controls that may be used during normal operation are not available to control start-up and shutdown emissions. SCR and oxidation catalysts require a minimum operating temperature to control emissions (for the catalytic reactions to occur for removal of NO_x and CO). This temperature is not reached until approximately 600 to 650°F. Although this temperature is reached in the HRSG before MECL, the CO and NO_x curves show that these emissions are unstable until around MECL. In addition, the manufacturer will only guarantee emissions down to MECL, indicating that this is where stability in these emissions is reached. To minimize emissions, however, start-up and shutdown shall be limited to 2 hours for start-up and 30 minutes for shutdown.

Therefore, no technically feasible control technologies for start-up and shutdown emissions from the combustion turbine have been identified.

5.7.3 Step 3. Rank the Technically Feasible Control Technologies

Since no technically feasible control technologies for start-up and shutdown emissions have been identified, ranking of such control technologies is not applicable.

5.7.4 Step 4. Evaluate the Most Effective Control Technologies

Since no technically feasible control options for start-up and shutdown emissions have been identified, evaluation of environmental, energy or economic impacts of such control technologies is not applicable.

5.7.5 Step 5. Proposed Start-up and Shutdown BACT Determination

BACT will include limiting combined-cycle operation to 1,525 hours per year for start-up and shutdown, combined, for natural gas operation and 42 start-ups and 42 shutdowns per year for fuel oil operation. Table 5-22 and Table 5-23 displays the BACT emission rates for start-up and shutdown emissions for the combustion turbine for natural gas and fuel oil operation, respectively.

Table 5-22: Combined-Cycle Combustion Turbine Natural Gas Start-up and Shutdown Emissions

Pollutant	Start-up Emissions			Shutdown Emissions	Start-up and Shutdown Emissions[a]
	lb/cold start	lb/warm start	lb/hot-fast start	lb/shutdown	tons per year
NO_x	335.0	233.0	111.0	59.0	108.3
CO	11,066	6,495	779.0	463.0	1,369
$PM/PM_{10}/PM_{2.5}$	43.6	29.1	16.3	10.9	16.6
VOC	950.0	558.0	67.0	40.0	117.8
H_2SO_4 mist	15.6	10.4	5.9	3.9	6.0
CO_2e	939,573	626,382	352,340	234,893	358,212

(a) Emissions are based on 1,525 hours per year for start-up and shutdown, combined, for natural gas operation.

Table 5-23: Combined-Cycle Combustion Turbine Fuel Oil Start-up and Shutdown Emissions

Pollutant	Start-up Emissions	Shutdown Emissions	Start-up and Shutdown Emissions[a]
	lb/start	lb/shutdown	tons per year
NO_x	860.0	108.0	20.3
CO	25,846	1,227	568.5
$PM/PM_{10}/PM_{2.5}$	78.9	19.7	2.1
VOC	2,951	122.0	64.5
H_2SO_4 mist	14.0	3.5	0.4
CO_2e	1,639,929	409,982	43,048

(a) Emissions are based on 42 start-ups and 42 shutdowns per year.

5.8 BACT for Opacity – Combined-Cycle Combustion Turbine (P01)

Previously submitted BACT Sections and updated references to the opacity BACT analysis sections for the combined cycle combustion turbine are presented in Table 5-24. The updated combined cycle combustion turbine opacity BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-24: Combustion Turbine Opacity BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D, December 2018 Submittal	Table D-1a (natural gas), Table D-1b (fuel oil) Appendix D
	--	Table D-1a Addendum (natural gas) Table D-1b Addendum (fuel oil) Appendix D

The following sections outline the top-down BACT steps for opacity emissions from the combustion turbine.

5.8.1 Step 1. Identify Potential Control Strategies

Opacity is not a discrete pollutant and cannot be measured using mass emissions rate criteria (e.g., lb/hr). Therefore, a typical top-down BACT economic analysis that evaluated effectiveness on a $/ton basis cannot be conducted on opacity. Rather, the opacity BACT determination should focus on pollutants in the flue gas that contribute to opacity. These pollutants include PM, NO_x, SO_2, and H_2SO_4. BACT determinations have been performed for PM, NO_x, and H_2SO_4 for this combined-cycle combustion turbine. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low exhaust opacity.

5.8.2 Step 2. Identify Technically Feasible Control Technologies

The Owners have prepared a detailed BACT evaluation for pollutants that potentially contribute to opacity. Based on these BACT evaluations, the Owners have identified the following control technologies as technically feasible: SCR and combustion control for NO_x control; low ash fuel and combustion control for PM control; and low sulfur and good combustion practices for H_2SO_4 mist. These technologies represent BACT for the criteria pollutants and will also minimize opacity.

5.8.3 Step 3. Rank the Technically Feasible Control Technologies

Based on these BACT evaluations, the Owners have ranked the following feasible control technologies for opacity: (1) combustion control, (2) clean fuels. The Owners have determined that the use of low ash fuel and combustion control combine to rank as the top option for opacity control.

5.8.4 Step 4. Evaluate the Most Effective Control Technologies

The energy, environmental, and economic impacts of the feasible control technologies are described in their respective BACT analysis.

5.8.5 Step 5. Proposed Opacity BACT Determination

BACT for exhaust opacity will include the use of combustion control for NO_x control, the use of low ash fuel and combustion control for PM control and the use of low sulfur fuel for H_2SO_4 mist control. The combination of these control technologies represents BACT for opacity.

5.9 BACT for Auxiliary Boiler (B02)

Previously submitted BACT Sections and updated references to the BACT analysis sections for the auxiliary boiler are presented in Table 5-25. Further analysis of the oxidation catalyst performed by the WDNR determined that an oxidation catalyst is economically feasible; therefore, the application text has been updated to reflect this update. The updated auxiliary boiler BACT analysis shows that the BACT determination in the PSD permit remain valid.

Table 5-25: Auxiliary Boiler BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
	Post application NTEC Response #3	Incorporated throughout Sections 5.9.2 and 5.9.4
RBLC	Table D-2, Appendix D December 2018 Submittal	Table D-2, Appendix D
	--	Table D-2 Addendum, Appendix D
Economic Tables	Tables E-1a, E-1b, E-2a, E-2b, E-3a, and E-3b, Appendix E, December 2018 Submittal	Appendix E

The auxiliary boiler is rated at 100 MMBtu/hr and is proposed to operate 8,760 hours per year. The RBLC has limited information on BACT conclusions for the auxiliary boiler (Appendix D). The RBLC tables also show high variability for emission rates for each pollutant. For all pollutants, no add-on controls were listed because auxiliary boilers are so small.

5.9.1 BACT for Nitrogen Oxides - Auxiliary Boiler

The following sections outline the top-down steps for NO_x emissions from the auxiliary boiler.

5.9.1.1 Step 1. Identify Potential Control Strategies

SCR, low-NO_x burners, combustion controls, and FGR are listed as BACT in the RBLC for auxiliary boilers. NO_x emissions listed in the RBLC range from 0.0085 to 0.36 lb/MMBtu for similar-sized auxiliary boilers utilizing low-NO_x burners and combustion controls. The RBLC listings for units with SCR range from 0.0032 to 0.015 lb/MMBtu.

5.9.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling NO_x emissions are evaluated for technical feasibility in the following sections.

5.9.1.2.1 SCR

The RBLC listed one unit with SCR as BACT for a similarly sized auxiliary boiler (approximately 100 MMBtu/hr). An SCR vendor said that they could provide an SCR for this size boiler. The vendor's removal efficiency for this size unit is 90 percent control of NO_x.

As a result, an SCR system is technically feasible for the auxiliary boiler.

5.9.1.2.2 Low-NO_x Burners

Low-NO_x burners are currently available from most auxiliary boiler manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing NO_x. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio, and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Low-NO_x burners are available on auxiliary boilers and are considered both baseline and technically feasible for the auxiliary boiler.

5.9.1.2.3 Ultra-Low NO_x Burners

Ultra-low NO_x burners are available for purchase on most auxiliary boilers of this size. The ultra-low NO_x burners provide additional control of NO_x emissions through the burning process.

Ultra-low NO_x burners are available on auxiliary boilers and is technically feasible for the auxiliary boiler.

5.9.1.2.4 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion. FGR is included as combustion control for this auxiliary boiler.

As a result, combustion control is considered baseline for the auxiliary boiler and is technically feasible.

5.9.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible NO_x control technologies for the 100 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 5-26.

Table 5-26. Ranking of NO_x Control Technologies for the Auxiliary Boiler

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
SCR	90	0.0036
Ultra-low NO_x burners	50	0.011
Low-NO_x burners, FGR, and combustion control	Not applicable (baseline)	0.036

Source: Based on vendor data

5.9.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.9.1.4.1 SCR

Energy and Environmental Impacts

Energy and environmental impacts for an SCR system are discussed in Section 5.1.4.1.

Economic Impacts

The capital costs and annualized costs associated with an SCR system for the auxiliary boiler are shown in Appendix E. The total capital investment of installing an SCR system on the auxiliary boiler is approximately $659,550. On an annual basis, the SCR system would cost almost $228,620 which results in a cost per ton of NO_x removed of approximately $15,264 while removing only 14.2 tons of NO_x per year. Therefore, this cost is considered not economically feasible for the auxiliary boiler.

An SCR is not considered economically feasible and is not proposed as BACT for the auxiliary boiler.

5.9.1.4.2 Ultra-Low-NO_x Burners

Energy and Environmental Impacts

Ultra-low-NO_x burners may decrease efficiency slightly on the auxiliary boiler, however these impacts are not significant.

Economic Impacts

The capital costs and annualized costs associated with installing ultra-low-NO_x burners on the auxiliary boiler are shown in Appendix E. The total capital investment of installing ultra-low-NO_x burners on the auxiliary boiler is approximately $150,765. On an annual basis, the ultra-low-NO_x burners would cost $66,868 which results in a cost per ton of NO_x removed of approximately $5,895 while removing 11.3 tons of NO_x per year. The cost to install ultra-low-NO_x burners is considered economically feasible by the Owners and is therefore considered BACT for the auxiliary boiler.

5.9.1.5 Low-NO_x Burners, FGR, and Combustion Control

Because the low-NO_x burners come standard on most auxiliary boilers and combustion control is accomplished through operation of the auxiliary boiler, there are no incremental energy, environmental, or economic impacts associated with these controls.

5.9.1.6 Steps 5. Proposed BACT for NO_x

Since ultra-low NO_x burners, FGR, and combustion control are considered economically feasible, and SCR is not economically feasible, ultra-low NO_x burners and FGR was selected as BACT for NO_x from the auxiliary boiler at an emission rate of 0.011 lb/MMBtu.

5.9.2 BACT for Carbon Monoxide - Auxiliary Boiler

The following sections outline the top-down steps for CO emissions from the auxiliary boiler.

5.9.2.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls in the BACT determinations for control of CO emissions from auxiliary boiler. As with the turbine, good combustion control will help control emissions of CO from the auxiliary boiler. An oxidation catalyst system may be available to control CO emissions from the auxiliary boiler, with one instance of an oxidation catalyst selected as BACT as listed in the RBLC database. Emission limits range from 0.0075 lb/MMBtu to 0.0842 lb/MMBtu.

5.9.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

5.9.2.2.1 Oxidation Catalyst System

One control vendor has indicated that an oxidation catalyst system may be used on an auxiliary boiler this size. The oxidation catalyst system is an add-on control that converts CO and VOC to CO_2 by use of a catalyst. Section 5.2.2.2 describes the oxidation catalyst system for gas-fired units. Due to the size of the auxiliary boiler, the exhaust gases do not need to be heated before going to the catalyst.

An oxidation catalyst system is considered technically feasible for the auxiliary boiler; one vendor has provided a quote for this system.

5.9.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

Good combustion practices are a technically feasible method of controlling CO emissions from the auxiliary boiler.

5.9.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the 100 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 5-27.

Table 5-27: Ranking of CO Control Technologies for the Auxiliary Boiler

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
Oxidation catalyst	90[a]	0.0037
Combustion control	Not applicable (baseline)	0.037

Source: Based on AP-42
(a) Control efficiencies were obtained from a vendor based on preliminary design and is consistent with other project oxidation catalyst control efficiencies. See Appendix F for vendor information.

5.9.2.4 Step 4. Evaluate the Most Effective Control Technologies

Technically feasible control technology was evaluated for energy, environmental, and economic impacts.

5.9.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 5.2.4.1.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the auxiliary boiler is displayed Appendix E. An oxidation catalyst system for this size unit would require a total capital investment of $147,225. The annual costs of operating this oxidation catalyst system would be $80,801. On an annual basis, only 14.6 tons per year of CO along with 1.2 tons per year of VOC would be removed at a cost of $5,125 per ton of pollutants removed, based on unlimited operation (8,760 hours per year).

The cost is considered economically feasible for an oxidation catalyst system; therefore, an oxidation catalyst for control of CO emissions from the auxiliary boiler is considered as BACT.

5.9.2.5 Step 5. Proposed BACT for CO

Since add-on controls are economically feasible for CO, an oxidation catalyst and combustion control was selected as BACT for CO from the auxiliary boiler at an emission rate of 0.0037 lb/MMBtu.

BACT for CO emissions from the auxiliary boiler is an oxidation catalyst and good combustion practices.

5.9.3 BACT for Particulate Matter - Auxiliary Boiler

The following sections outline the top-down steps for PM/PM_{10}/$PM_{2.5}$ emissions from the auxiliary boiler.

5.9.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas). No add-on controls were identified for significant removal of these pollutants from the auxiliary boiler exhaust. The RBLC lists emission rates of 0.005 lb/MMBtu for similar sized auxiliary boilers (approximately 100 MMBtu/hr) up to 0.020 lb/MMBtu.

5.9.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for PM/PM_{10}/$PM_{2.5}$.

5.9.3.3 Step 3. Rank the Technically Feasible Control Technologies

The only technically feasible control option is combustion control for $PM/PM_{10}/PM_{2.5}$.

5.9.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for $PM/PM_{10}/PM_{2.5}$

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for $PM/PM_{10}/PM_{2.5}$ from the auxiliary boiler at an emission rate of 0.01 lb/MMBtu.

5.9.4 BACT for Volatile Organic Compounds - Auxiliary Boiler

The following sections outline the top-down steps for VOC emissions from the auxiliary boiler.

5.9.4.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls in the BACT determinations for control of VOC emissions from auxiliary boiler. As with the turbine, good combustion control will help control emissions of VOC from the auxiliary boiler. An oxidation catalyst system may be available to control VOC and CO emissions from the auxiliary boiler, with two VOC entries listed as BACT for VOC emissions. Emission rates vary from the various sized auxiliary boiler, but at 100 MMBtu/hr approximate size, the lowest emission limit is 0.005 lb/MMBtu, with good combustion practices.

5.9.4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

5.9.4.2.1 Oxidation Catalyst System

One control vendor has indicated that an oxidation catalyst system may be used on an auxiliary boiler this size. The oxidation catalyst system is an add-on control that converts CO and VOC to CO_2 by use of a catalyst. Section 5.4.2.2 describes the oxidation catalyst system for gas-fired units. Due to the size of the auxiliary boiler, the exhaust gases do not need to be heated before going to the catalyst.

An oxidation catalyst system is considered technically feasible for the auxiliary boiler; one vendor has provided a quote for this system.

5.9.4.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed auxiliary boiler.

5.9.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the 100 MMBtu/hr auxiliary boiler are ranked by control effectiveness in Table 5-28.

Table 5-28: Ranking of VOC Control Technologies for the Auxiliary Boiler

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
Oxidation catalyst	50[a]	0.0027
Combustion control	Not applicable (baseline)	0.005

Source: Based on AP-42
(a) Control efficiencies were obtained from a vendor based on preliminary design and is consistent with other project oxidation catalyst control efficiencies. See Appendix F for vendor information.

5.9.4.4 Step 4. Evaluate the Most Effective Control Technologies

Technically feasible control technology was evaluated for energy, environmental, and economic impacts.

5.9.4.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 5.4.4.1.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the auxiliary boiler is displayed in Appendix E and are the same as those provided for the CO BACT analysis. An oxidation catalyst system for this size unit would require a total capital investment of $147,225. The annual costs of operating this oxidation catalyst system would be $80,801. On an annual basis, only 14.6 tons per year of CO along with 1.2 tons per year of VOC would be removed at a cost of almost $5,125 per ton of pollutants removed, based on unlimited operation (8,760 hours per year).

The cost is considered economically feasible for an oxidation catalyst system; therefore, an oxidation catalyst for control of VOC emissions from the auxiliary boiler is considered as BACT.

5.9.4.5 Step 5. Proposed BACT for VOC

Since add-on controls are economically feasible for VOC, an oxidation catalyst and combustion control was selected as BACT for VOC from the auxiliary boiler at an emission rate of 0.0027 lb/MMBtu.

BACT for VOC emissions from the auxiliary boiler is an oxidation catalyst and good combustion practices.

5.9.5 BACT for Sulfuric Acid Mist – Auxiliary Boiler

The following sections outline the top-down steps for H_2SO_4 emissions from the auxiliary boiler.

5.9.5.1 Step 1-5 Identify, Rank and Select BACT

There are no add-on control technologies for controlling H_2SO_4 emissions from an auxiliary boiler. As with the combustion turbine, using low sulfur fuel and controlling combustion is the only technologically feasible control option.

BACT is use of lower sulfur fuel and good combustion practices. This will achieve an emission rate of 0.01 pounds per hour of H_2SO_4 from the auxiliary boiler.

5.9.6 BACT for Greenhouse Gases - Auxiliary Boiler (Steps 1-5)

The auxiliary boiler will be fired exclusively on natural gas, is rated at 100 MMBtu/hr, and will be permitted to be fired a total of 8,760 hours per year. GHG emissions from this unit are estimated to be on the order of 51,289 tons CO_2e per year. The basic GHG BACT reasoning presented for the turbine essentially applies to this boiler as well. The Owners propose that GHG BACT for this boiler will be the following:

- Use of clean fuels (exclusive use of natural gas)
- Requiring the Owners to maintain the unit according to the manufacturer’s specifications, and to operate the unit in the most efficient manner possible, i.e. good combustion practices.
- Tune the unit every two years according to the manufacturer’s specifications.
- Record the annual hours of operation and annual fuel use and report the GHG emissions annually. The GHG emissions from this unit may be included in the facility-wide annual GHG limit.

5.9.7 BACT for Opacity - Auxiliary Boiler

The following sections outline the top-down steps for opacity emissions from the auxiliary boiler.

5.9.7.1 Step 1. Identify Potential Control Strategies

Opacity is not a discrete pollutant and cannot be measured using mass emissions rate criteria (e.g., lb/hr). Therefore, a typical top-down BACT economic analysis that evaluated effectiveness on a $/ton basis cannot be conducted on opacity. Rather, the opacity BACT determination should focus on pollutants in the flue gas that contribute to opacity. These pollutants include PM, NO_x, SO_2, and H_2SO_4. BACT determinations have been done for PM, NO_x and H_2SO_4 for this auxiliary boiler. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low exhaust opacity.

5.9.7.2 Step 2. Identify Technically Feasible Control Technologies

The Owners have prepared a detailed BACT evaluation for pollutants that potentially contribute to opacity. Based on these BACT evaluations, the Owners have identified the following control technologies as technically feasible: SCR and combustion control for NO_x control; and low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. These technologies represent BACT for the criteria pollutants and will also minimize opacity.

5.9.7.3 Step 3. Rank the Technically Feasible Control Technologies

Based on these BACT evaluations, the Owners have ranked the following feasible control technologies for opacity: (1) combustion control, (2) clean fuels. The Owners have determined that the use of low ash, low sulfur fuel and combustion control combine to rank as the top option for opacity control.

5.9.7.4 Step 4. Evaluate the Most Effective Control Technologies

The energy, environmental, and economic impacts of the feasible control technologies are described in their respective BACT analysis.

5.9.7.5 Step 5. Proposed Opacity BACT Determination

BACT for exhaust opacity will include the use of combustion control for NO_x control and the use of low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. The combination of these control technologies represents BACT for opacity for the auxiliary boiler.

5.10 BACT for Greenhouse Gases (GHG) – SF_6-Containing Circuit Breakers (F03)

Previously submitted BACT Sections, post application submittals, and updated references to the BACT analysis sections for the SF_6-containing circuit breakers are presented in Table 5-29. The updated circuit breaker BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-29: SF6-Containing Circuit Breakers BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
RBLC	Table 2-4 December 2018 Submittal	Table D-7, Appendix D
	--	Table D-7 Addendum, Appendix D
Evaluation of leakage rate	September 1, 2020 letter submittal to WDNR	Appendix F - Additional Information

SF_6 is a very potent GHG with a GWP of 22,800, which means that it is 22,800 times more potent as a GHG than CO_2. SF_6 is a gaseous dielectric used in circuit breakers. The Project is expected to have three 345-kV circuit breakers and two 19-kV circuit breakers that will all contain small amounts of SF_6. Leakage is expected to be minimal and is expected to occur only as a result of circuit interruption and at extremely low temperatures.

Emissions of SF_6 from the circuit breakers are shown in Appendix C. Annual potential to emit emissions of SF_6 from the circuit breakers were based on maximum leakage rate of 0.5 percent per year, the amount of SF_6 in each size of circuit breaker, and the GWP. Project potential emissions of CO_2e leakage from all proposed circuit breakers combined are estimated to be 120 tons per year.

The following sections outline the top-down steps for GHG emissions from the SF_6-circuit breakers.

5.10.1 Step 1 and Step 2. Identify Potential Control Strategies and Eliminate Technologically Infeasible Options

The first steps in a top-down BACT analysis are to determine the potential control strategies and then determine if the control strategy is technically feasible for the Project. There are no add-on control technologies for SF_6; only inherent controls are available. The following control strategies have been identified and considered in determining BACT for SF_6 emissions from circuit breakers:

1. **Use state-of-the-art SF_6 technology with leak detection systems to limit fugitive emissions.**

   The use of state-of-the-art gas-filled circuit breakers using SF_6 with leak detection to limit fugitive emissions is the proposed control option. Modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions than older circuit breakers. The current International Electrotechnical Commission (IEC) standards are that new equipment be built to low leakage limits (less than 0.5 percent per year) (Blackman, et al., 2019).

The effectiveness of these leak-tight closed systems is further enhanced by equipping them with an alarm that provides a warning when SF_6 has leaked from the breaker. Therefore, this type of technology is available to limit emissions, is feasible for use, and is the baseline established for this BACT analysis.

2. **Substitution of another, non-greenhouse-gas substance for SF_6 such as the use of a different dielectric oil or compressed air (air-blast) circuit breaker as the dielectric material in the breakers.**

One alternative to SF_6 would be the use of a dielectric oil or compressed air (air-blast) circuit breakers, which historically were used in high-voltage installations prior to the development of SF_6 breakers. SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities over oil and air-blast circuit breakers. The main drawback to oil and air-blast breakers are that these types of breakers require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers and air-blast breakers can have significant noise impacts to nearby residences. This type of technology is not feasible for use here, however, because oil breakers are no longer available from vendors, other than as used equipment. According to vendors, air-blast breakers are available only for breakers below 69-kV currently, but were also not available for the very small 19-kV circuit breakers also proposed for this Project. Therefore, oil and air-blast breakers are not available control technology for circuit breakers proposed for the Project.

3. **Use an emerging technology to replace SF_6 with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.**

The availability of emerging technology alternatives to SF_6 was researched. According to the most recent report released by the EPA SF_6 Partnership, there is no clear alternative to SF_6 (EPA, 2015). Research and development efforts have been focused on finding substitutions for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications (U.S. Climate Change Technology Program, 2003). Most studies have concluded "there is no replacement gas immediately available to use as an SF_6 substitute" for high-voltage applications (Siemens Industry, Inc., 2013). Therefore, the alternative to use an emerging technology to replace SF_6 is not an available control technology.

Table 5-30 displays the control options and feasibility for SF_6.

Table 5-30. Summary of Potential GHG Control Technologies

GHG Technology	Evaluation Status
State-of-the-art SF_6 technology with leak detection systems	Considered and applied
Oil/air-blast circuit breakers	Considered (Not Feasible)
Use of emerging technology to replace SF_6	Considered (Not Feasible)

5.10.2 Step 3. Rank the Technically Feasible Control Technologies

Table 5-31 presents the ranked technically feasible control options.

Table 5-31. GHG Technology Rankings for Circuit Breaker Equipment Leaks

Control Technology	Emission Rate (short tons CO_2e/year)	Emissions Reduction (short tons CO_2e/year)
State-of-the-art SF_6 technology with leak detection systems	120	N/A

5.10.3 Step 4. Evaluate the Most Effective Control Technologies

The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

5.10.3.1 Environmental, Energy, and Economic Feasibility of Control Options

Purchasing leak detection systems for the circuit breakers will come with a cost: however, the costs are not considered not economically feasible for this Project.

Further information was provided to WDNR that confirms the circuit breakers selected are consistent with the best that is presently available and are 'state of the art' and addresses why a 0.1 percent leakage rate is not achievable. This additional information letter submitted to the WDNR on September 1, 2020 is included in Appendix F for reference.

5.10.4 Step 5. GHG BACT Emission Limitation

The proposed BACT for the circuit breakers consists of the following:

- State-of-the-art enclosed-pressure SF_6 circuit breakers with a guaranteed loss rate of 0.5 percent by weight or less by year; and
- Low-pressure detection system with alarm system

A review of the RBLC for circuit breakers containing SF_6 (most of them combined-cycle plants) have a similar or the same BACT determination. As shown in Appendix D, a leak detection rate of 0.5 percent from enclosed pressured design with leak detection alarms is BACT.

5.10.5 Compliance with GHG BACT for Circuit Breakers

Any SF_6 emissions from the circuit breakers will be fugitive emissions. Fugitive emissions are, by their nature, very difficult to monitor directly, as they are not emitted from a discrete emission point. Therefore, the Owners propose the following compliance demonstrations, recordkeeping and monitoring requirements:

1. Follow manufacturer recommendations for maintenance and repair of the affected breakers, with recovery and recycling of SF_6 removed during maintenance procedures.
2. Install a low-pressure detection system with an alarm system on each SF_6 circuit breaker to measure pressure changes.
3. Create alarms based on the pressure readings in the breakers, so that leaks can be detected before a substantial portion of SF_6 is lost.
4. Upon a detectable pressure drop that is 10 percent of the original pressure (accounting for ambient air conditions), perform maintenance on a breaker to fix seals within 20 days of the detection of the pressure drop.
5. Keep a log of all detected leaks and maintenance procedures potentially affecting SF_6 emissions from circuit breakers that are part of this Project.
6. For a period of at least 5 years, track and maintain records of annual SF_6 leakage amounts due to breakers that are part of this Project. The leakage amounts will be assumed equal to the inventory of SF_6 replaced in the breakers each calendar year.

These proposed work practices are consistent with the BACT determinations identified above.

5.11 BACT for Natural Gas Heaters (P04 and P05)

Previously submitted BACT Sections, post-application submittals, and updated references to the BACT analysis sections for the natural gas heaters are presented in Table 5-32. The updated natural gas heaters BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-32: Natural Gas Heaters BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	December 2018 Submittal	5.0 BACT
	Post application NTEC Response #15	Incorporated into Section 5.11.1
RBLC	Table D-4, Appendix D December 2018 Submittal	Table D-4, Appendix D
	Addendum update	Table D-4 Addendum Appendix D
Economic Tables	Tables E-3a, E-3b, E-4a, E-4b December 2018 Submittal	Appendix E
	Table 1a & Table 1b Post application NTEC Response #15	Appendix E

There are two natural gas heaters proposed as part of the Project. The heaters heat natural gas prior to entering the facility and are fired by natural gas, a clean-burning fuel. Each heater is rated at 10.0 MMBtu/hr and is proposed to operate 8,760 hours per year each. The RBLC has limited information on BACT conclusions for heaters (Appendix D). The RBLC tables also show high variability for emission rates for each pollutant. For all pollutants, no add-on controls were listed because gas heaters are so small.

5.11.1 BACT for Nitrogen Oxides – Gas Heaters

The following sections outline the top-down steps for NO_x emissions from the gas heaters.

5.11.1.1 Step 1. Identify Potential Control Strategies

There are no add-on NO_x control techniques available for units of this size. Ultra-low NO_x burners, low-NO_x burners, along with combustion controls, are listed as BACT in the RBLC for the gas heaters. NO_x emissions listed in the RBLC range from 0.013 to 0.2466 lb/MMBtu for similar sized gas heater utilizing low-NO_x burners and combustion controls.

In discussions with vendors, multiple vendors stated that they cannot meet the 0.013 NO_x emission rate with low-NO_x burners. It was determined that the emission rate of 0.013 lb/MMBtu is in line with vendor quotes for ultra-low-NO_x burners.

The natural gas heaters installed for the Project will be equipped with low NO_x burners. Since the vendor has not been selected yet, the natural gas heater NO_x emission factor listed in the application is based on the emission factor listed in AP-42 Section 1.4, Table 1.4-1 for small boilers (<100 MMBtu/hr) controlled by low NO_x burners. This value is consistent with other BACT units with low NO_x burners listed in the RBLC.

Because there are lower emission limits presented in the RBLC, vendors were contacted to determine what NO_x control options were available for natural gas heaters of this size. Low NO_x burners are standard on these natural gas heaters; however, to achieve the lower NO_x levels reported in the RBLC, the vendors stated that this would require ultra-low NO_x burners. As such, the costs and emission guarantees for ultra-low NO_x burners were obtained from the vendors. As required by a top-down BACT analysis, evaluation of this additional control was completed.

5.11.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling NO_x emissions are evaluated for technical feasibility in the following sections.

5.11.1.2.1 SCR

Although the RBLC did not list any add-on control devices as BACT for a gas heater, one SCR vendor said that they could provide an SCR for this size unit. The vendor's removal efficiency for this size unit is 90 percent control of NO_x.

As a result, an SCR system is technically feasible for the gas heaters.

5.11.1.2.2 Low-NO_x Burners

Low-NO_x burners are currently available from most gas heater manufacturers. This technology seeks to reduce combustion temperatures, thereby reducing NO_x. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio, and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Low-NO_x burners are available on the gas heaters and are considered both baseline and technically feasible.

5.11.1.2.3 Ultra-Low-NO_x Burners

Ultra-low-NO_x burners are available on the gas heaters and is considered technically feasible.

5.11.1.2.4 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the gas heaters and is technically feasible.

5.11.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible NO_x control technologies for the 10.0 MMBtu/hr gas heaters are ranked by control effectiveness in Table 5-33.

Table 5-33: Ranking of NO_x Control Technologies for the Gas Heaters

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
SCR	90	0.0049
Ultra-low NO_x burners	73	0.013
Low-NO_x burners and combustion control	Not applicable (baseline)	0.049

5.11.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.11.1.4.1 SCR

<u>Energy and Environmental Impacts</u>

Energy and environmental impacts for an SCR system are discussed in Section 5.1.4.1.

<u>Economic Impacts</u>

The capital costs and annualized costs associated with an SCR system for each gas heater was evaluated and the analysis is located in Appendix E. The total capital investment of installing an SCR system on the gas heater is approximately $137,910. On an annual basis, the SCR system would cost approximately $103,539, which results in a cost per ton of NO_x removed of almost $53,604 while removing only 1.9 tons of NO_x per year. Therefore, any control of NO_x by add-on controls would result in costs that would not be economical.

An SCR is not proposed as BACT for the gas heaters because it is not economically feasible.

5.11.1.4.2 Ultra-Low-NO_x Burners and Combustion Control

Energy and Environmental Impacts

Ultra-low NOx burners may decrease efficiency slightly on the natural gas heaters; however, these impacts are not significant.

Economic Impacts

The economic impacts of installing an ultra-low-NO_x burner on the natural gas heaters were evaluated. The capital costs and annualized costs associated with installing ultra-low-NO_x burners on the natural gas heaters are in Appendix E. The total capital investment of installing ultra-low-NO_x burners on each natural gas heater is approximately $25,990. On an annual basis, the ultra-low-NO_x burners would cost $22,526 which results in a cost per ton of NO_x removed of approximately $13,187 while removing only an additional 1.7 tons of NO_x per year over the standard low-NO_x burners. Installing and operating ultra-low-NO_x burners results in costs that are economically infeasible.

5.11.1.4.3 Low-NO_x Burners and Combustion Control

Because the low-NO_x burners come standard on most gas heaters and combustion control is accomplished through operation of the gas heater, there are no incremental energy, environmental, or economic impacts associated with these controls.

5.11.1.5 Step 5. Proposed NO_x Gas Heaters BACT Determination

Low-NO_x burners and combustion control was selected as BACT for the gas heaters; add-on controls are not practical on this small unit since the economic impacts are high. The low-NO_x burners can achieve an emission rate of 0.049 lb/MMBtu during steady state operation.

5.11.2 BACT for Carbon Monoxide – Gas Heaters

The following sections outline the top-down steps for CO emissions from gas heaters.

5.11.2.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls for gas heater in the BACT determinations for control of CO emissions from gas heaters; however, one control vendor has indicated that an oxidation catalyst system may be used on a gas heater this size. As with the combustion turbines, good combustion control will help control emissions of CO from the gas heaters. CO emissions listed in the RBLC range from 0.0075 to 0.1108 lb/MMBtu for similar sized gas heater utilizing combustion controls and clean fuels. A majority of the gas heaters listed in the RBLC that are less than 0.08 lb/MMBtu are much larger than the proposed gas heaters for this Project.

5.11.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

5.11.2.2.1 Oxidation Catalyst System

One control vendor has indicated that an oxidation catalyst system may be used on a gas heater this size. The oxidation catalyst system is an add-on control that converts CO and VOC to CO_2 by use of an oxidation catalyst. Section 5.2.2.2 describes the oxidation catalyst system for gas-fired units.

An oxidation catalyst system is considered technically feasible for the gas heaters; one vendor has provided a quote for this system.

5.11.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

Good combustion practices are a technically feasible method of controlling CO emissions from the gas heaters.

5.11.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the 10.0 MMBtu/hr gas heaters are ranked by control effectiveness in Table 5-34.

Table 5-34: Ranking of CO Control Technologies for the Gas Heaters

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
Oxidation catalyst	90	0.008
Combustion control	Not applicable (baseline)	0.08

5.11.2.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.11.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts of an oxidation catalyst are discussed in Section 5.2.4.1.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the gas heater is displayed in Appendix E. An oxidation catalyst system for this size unit would require a total capital investment of $33,582. The annual costs of operating this oxidation catalyst system would be $34,849. On an annual basis, only 3.2 tons per year of CO along with 0.07 tons per year of VOC would be removed at a cost of almost $10,550 per ton of pollutants removed.

The cost is considered economically infeasible; therefore, an oxidation catalyst for control of CO emissions from the gas heaters is not considered BACT.

5.11.2.5 Step 5. Proposed BACT for CO

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for CO from the gas heaters at an emission rate of 0.08 lb/MMBtu.

BACT for CO emissions from the gas heaters is good combustion practices.

5.11.3 BACT for Particulate Matter – Gas Heaters

The following sections outline the top-down steps for PM/PM_{10}/$PM_{2.5}$ emissions from gas heaters.

5.11.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas). No add-on controls were identified for significant removal of these pollutants from the gas heater exhaust.

5.11.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for PM/PM_{10}/$PM_{2.5}$.

5.11.3.3 Step 3. Rank the Technically Feasible Control Technologies

The only technically feasible control option is combustion control for PM/PM_{10}/$PM_{2.5}$.

5.11.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for $PM/PM_{10}/PM_{2.5}$

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for $PM/PM_{10}/PM_{2.5}$ from the gas heaters at an emission rate of 0.01 lb/MMBtu.

5.11.4 BACT for Volatile Organic Compounds – Gas Heaters

The following sections outline the top-down steps for VOC emissions from gas heaters.

5.11.4.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls for gas heaters in the BACT determinations for control of VOC emissions; however, one control vendor has indicated that an oxidation catalyst system may be used on a gas heater this size. As with the combustion turbines, good combustion control will help control emissions of VOC from the gas heaters.

5.11.4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

5.11.4.2.1 Oxidation Catalyst System

One control vendor has indicated that an oxidation catalyst system may be used on a gas heater this size. The oxidation catalyst system is an add-on control that converts CO and VOC to CO_2 by use of a catalyst. Section 5.4.2.2 describes the oxidation catalyst system for gas-fired units.

An oxidation catalyst system is considered technically feasible for the gas heaters; one vendor has provided a quote for this system.

5.11.4.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

Good combustion practices are a technically feasible method of controlling VOC emissions from the gas heaters.

5.11.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the 10.0 MMBtu/hr gas heaters is ranked by control effectiveness in Table 5-35.

Table 5-35: Ranking of VOC Control Technologies for the Gas Heaters

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
Oxidation catalyst	30	0.0038
Combustion control	Not applicable (baseline)	0.005

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.11.4.4 STEP 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.11.4.4.1 Oxidation Catalyst

<u>Energy and Environmental Impacts</u>

Energy and environmental impacts of an oxidation catalyst are discussed in Section 5.4.4.1.

<u>Economic Impacts</u>

The control cost analysis for an oxidation catalyst system for the gas heater is displayed in Appendix E. An oxidation catalyst system for this size unit would require a total capital investment of $33,582. The annual costs of operating this oxidation catalyst system would be $34,849. On an annual basis, only 3.2 tons per year of CO along with only 0.07 tons per year of VOC would be removed at a cost of almost $10,550 per ton of pollutants removed.

The cost is considered economically infeasible; therefore, an oxidation catalyst for control of VOC emissions from the gas heaters is not considered BACT.

5.11.4.5 STEP 5. Proposed BACT for VOC

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for VOC from the gas heaters at an emission rate of 0.005 lb/MMBtu.

BACT for VOC emissions from the gas heaters is good combustion practices.

5.11.5 BACT for Sulfuric Acid Mist – Gas Heaters

The following sections outline the top-down steps for H_2SO_4 emissions from the gas heaters.

5.11.5.1 Step 1-5 Identify, Rank and Select BACT

There are no add-on control technologies for controlling H_2SO_4 emissions from a gas heater. As with the combustion turbines, using low sulfur fuel and controlling combustion is the only technologically feasible control option.

BACT is use of lower sulfur fuel and good combustion practices. This will achieve an emission rate of 3.9×10^{-3} tons per year of H_2SO_4 from each of the gas heaters.

5.11.6 BACT for Greenhouse Gases – Gas Heaters (Steps 1-5)

The gas heaters as proposed will be fired exclusively on natural gas and used to pre-heat natural gas fuel to facilitate start-up. The units are each rated at approximately 10.0 MMBtu/hr and will be permitted to be fired a total of 8,760 hours per year each. GHG emissions from this unit are estimated to be on the order of 5,129 tons CO_2e per year, each. These GHG emissions are also *de minimis*, when compared to the turbine GHG emissions or the facility total GHG emissions. The basic GHG BACT reasoning presented for the turbines essentially applies to this heater as well. The Owners propose that GHG BACT for these units will be the following:

- Use of clean fuels (exclusive use of natural gas)
- Requiring the Owners to maintain the unit according to the manufacturer's specifications, and to operate the unit in the most efficient manner possible, i.e. good combustion practices
- Tune the unit every two years according to the manufacturer's specifications
- Record the annual hours of operation and annual fuel use and report the GHG emissions annually. The GHG emissions from this unit may be included in the facility-wide annual GHG limit.

5.11.7 BACT for Opacity - Gas Heaters

The following sections outline the top-down steps for opacity emissions from gas heaters.

5.11.7.1 Step 1. Identify Potential Control Strategies

Opacity is not a discrete pollutant and cannot be measured using mass emissions rate criteria (e.g., lb/hr). Therefore, a typical top-down BACT economic analysis that evaluated effectiveness on a $/ton basis cannot be conducted on opacity. Rather, the opacity BACT determination should focus on pollutants in the flue gas that contribute to opacity. These pollutants include PM, NO_x, SO_2, and H_2SO_4. BACT determinations have been done for PM, NO_x and H_2SO_4 for the gas heaters. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low exhaust opacity.

5.11.7.2 Step 2. Identify Technically Feasible Control Technologies

The Owners have prepared a detailed BACT evaluation for pollutants that potentially contribute to opacity. Based on these BACT evaluations, the Owners have identified the following control technologies as technically feasible: SCR and combustion control for NO_x control; and low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. These technologies represent BACT for the criteria pollutants and will also minimize opacity.

5.11.7.3 Step 3. Rank the Technically Feasible Control Technologies

Based on these BACT evaluations, the Owners have ranked the following feasible control technologies for opacity: (1) combustion control, (2) clean fuels. The Owners have determined that the use of low ash, low sulfur fuel and combustion control combine to rank as the top option for opacity control.

5.11.7.4 Step 4. Evaluate the Most Effective Control Technologies

The energy, environmental, and economic impacts of the feasible control technologies are described in their respective BACT analysis.

5.11.7.5 Step 5. Proposed Opacity BACT Determination

BACT for exhaust opacity will include the use of combustion control for NO_x control and the use of low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. The combination of these control technologies represents BACT for opacity for the gas heaters.

5.12 BACT Analysis for Emergency Diesel Fire Pump (P06)

Previously submitted BACT Sections, post application submittals, and updated references to the BACT analysis sections for the emergency diesel fire pump are presented in Table 5-36. The updated emergency diesel fire pump BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-36: Emergency Diesel Fire Pump BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT
	Post application NTEC Response #18	Incorporated into Section 5.12.3
RBLC	Appendix D, Table D-6 December 2018 Submittal	Appendix D, Table D-6
	--	Table D-6 Addendum, Appendix D
Economic Tables	Table 1 and Table 2 Post application NTEC Response #11	Appendix E

One 282-hp emergency diesel-fired fire pump will be installed for the Project. The emergency diesel fire pump will be limited to 500 hours per year (100 hours per year for testing and maintenance purposes) and will utilize ultra-low sulfur transportation-grade distillate fuel oil, with a sulfur content of no more than 0.0015 weight percent. The emergency diesel fire pump will comply with the applicable NSPS requirements. The RBLC has limited information on BACT conclusions for small engines such as the emergency diesel fire pump (Appendix D). The RBLC tables also show high variability for emission rates for each pollutant. For all pollutants, no add-on controls were listed because the add-on controls were determined to not be economically feasible due to engine size.

BACT can be no less stringent than the NSPS Subpart IIII limits, which are discussed in Section 4.2.5.

5.12.1 BACT for Nitrogen Oxides – Emergency Diesel Fire Pump

The following sections outline the top-down steps for NO_x emissions from the emergency diesel fire pump.

5.12.1.1 Step 1. Identify Potential Control Strategies

For an emergency diesel fire pump that only operates 500 hours per year, there are no controls that are available that would approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul an SCR catalyst in a short amount of operating time. For the purposes of this BACT analysis, however, it is assumed that an SCR system may be technically feasible.

5.12.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling NO_x emissions are evaluated for technical feasibility in the following sections.

5.12.1.2.1 SCR

The RBLC did not list any add-on control devices as BACT for the emergency diesel fire pump; however, an SCR may be available for this size of engine.

As a result, an SCR system is considered technically feasible for the emergency diesel fire pump.

5.12.1.2.2 Combustion Control and Clean Fuels

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control and clean fuels are considered baseline for the emergency diesel fire pump and is technically feasible.

5.12.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible NO_x control technologies for the emergency diesel fire pump are ranked by control effectiveness in Table 5-37.

Table 5-37: Ranking of NO_x Control Technologies for the Emergency Diesel Fire Pump

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
SCR	90	0.30
Combustion Control and Clean Fuels	Not applicable (baseline)	3.0

5.12.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.12.1.4.1 SCR

Energy and Environmental Impacts

Energy and environmental impacts for an SCR system are discussed in Section 5.1.4.1.

Economic Impacts

Because this unit will only operate 500 hours per year, a cost analysis is not needed to show that the cost per ton of NO_x removed would be economically infeasible. The emergency diesel fire pump will only emit 0.47 tons per year of NO_x, based on the annual 500-operating hour limitation.

Therefore, an SCR is not proposed as BACT because it is not economically feasible for the emergency diesel fire pump.

5.12.1.4.2 Combustion Control and Clean Fuels

Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

5.12.1.5 Step 5. Proposed NO_x Emergency Diesel Fire Pump BACT Determination

Combustion control and clean fuels were selected as BACT for NO_x for the emergency diesel fire pump; add-on controls are not practical on a unit this size, with limited operation, and the economic impacts are high. The emergency diesel fire pump will be able to achieve 3.0 g/hp-hr of NO_x emissions on an on-going basis.

5.12.2 BACT for Carbon Monoxide – Emergency Diesel Fire Pump

The following sections outline the top-down steps for CO emissions from the emergency diesel fire pump.

5.12.2.1 Step 1. Identify Potential Control Strategies

For an engine that only operates 500 hours per year for testing and maintenance, there are no controls that are available that would even approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul an oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an oxidation catalyst may be technically feasible.

5.12.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

5.12.2.2.1 Oxidation Catalyst

The RBLC did not list any add-on control devices as BACT for the emergency diesel fire pump; however, an oxidation catalyst may be available for this small engine size.

As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel fire pump.

5.12.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the emergency diesel fire pump and is technically feasible.

5.12.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the emergency diesel fire pump are ranked by control effectiveness in Table 5-38.

Table 5-38: Ranking of CO Control Technologies for the Emergency Diesel Fire Pump

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Oxidation Catalyst	90	0.26
Combustion Control	Not applicable (baseline)	2.6

5.12.2.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.12.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.2.4.1.

<u>Economic Impacts</u>

The control cost analysis for an oxidation catalyst system for the emergency fire pump is shown in Appendix E. An oxidation catalyst system for this size unit would require a total capital investment of $23,660. The annual costs of operating this oxidation catalyst system would be $5,838. On an annual basis, only 0.32 tons per year of CO and 0.09 tons per year of VOC would be removed at a total cost of $14,326 per ton of both pollutants removed, based on limited operation of 500 hours per year.

Keep in mind that normal operation for this unit will be testing and maintenance for less than one hour per week and results costs for the add- on controls would be much, much higher. Even when considering emergency operation for up to 500 hours per year, the cost for adding an oxidation catalyst to the emergency fire pump is considered economically infeasible; therefore, an oxidation catalyst for control of CO and VOC emissions from the emergency fire pump is not considered BACT. Additionally, since the emergency fire pump will typically operate for less than one hour during routine maintenance and testing, the emissions will be uncontrolled since it takes time for the catalyst to warm-up to optimal operating temperature; therefore, an oxidation catalyst is not an effective control technology.

Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel fire pump.

5.12.2.4.2 Combustion Control

Combustion control is accomplished through operational control of the engine, therefore, there are no energy, environmental, or economic impacts associated with this control.

5.12.2.5 Step 5. Proposed CO Emergency Diesel Fire Pump BACT Determination

Combustion control was selected as BACT for CO for the emergency diesel fire pump; add-on controls are not practical on this small unit with limited operation and economic impacts are high. The emergency diesel fire pump will be able to achieve 2.6 g/hp-hr of CO emissions on an on-going basis.

5.12.3 BACT for Particulate Matter – Emergency Diesel Fire Pump

The following sections outline the top-down steps for particulate matter emissions from the emergency diesel fire pump.

5.12.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas) for the emergency diesel fire pump.

A diesel particulate filter was deemed technically infeasible for the fire pump as the National Fire Protection Association, Underwriters Laboratories and Factory Mutual will not allow a particulate filter to be installed on the exhaust stack of a fire pump. This is because it is possible for this filter to become clogged, rendering the diesel engine inoperable.

No add-on controls were identified for significant removal of these pollutants from the engine's exhaust.

5.12.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for $PM/PM_{10}/PM_{2.5}$.

5.12.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies for the emergency diesel fire pump are ranked by control effectiveness in Table 5-39.

Table 5-39: Ranking of $PM/PM_{10}/PM_{2.5}$ Control Technologies for the Emergency Diesel Fire Pump

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Combustion Control and Clean Fuels	Not applicable (baseline)	0.15

5.12.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for $PM/PM_{10}/PM_{2.5}$

Since no add-on controls were identified, combustion control with low ash fuel was selected as BACT for $PM/PM_{10}/PM_{2.5}$ at an emission rate of 0.15 g/hp-hr for the emergency diesel fire pump.

5.12.4 BACT for Volatile Organic Compounds – Emergency Diesel Fire Pump

The following sections outline the top-down steps for VOC emissions from the emergency diesel fire pump.

5.12.4.1 Step 1. Identify Potential Control Strategies

For an engine that only operates 500 hours per year for testing and maintenance, there are no controls that are available that would even approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul the oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis; however, it is assumed that an oxidation catalyst may be technically feasible.

5.12.4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

5.12.4.2.1 Oxidation Catalyst

Although the RBLC did not list any add-on control devices as BACT for the emergency diesel fire pump, an oxidation catalyst may be available for this small engine.

As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel fire pump.

5.12.4.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the emergency diesel fire pump and is technically feasible.

5.12.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the emergency diesel fire pump are ranked by control effectiveness in Table 5-40.

Table 5-40: Ranking of VOC Control Technologies for the Emergency Diesel Fire Pump

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Oxidation Catalyst	20	0.91
Combustion Control	Not applicable (baseline)	1.1

5.12.4.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.12.4.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.4.4.1.

Economic Impacts

The control cost analysis for an oxidation catalyst system for the emergency fire pump is shown in Appendix E. An oxidation catalyst system for this size unit would require a total capital investment of $23,660. The annual costs of operating this oxidation catalyst system would be $5,838. On an annual basis, only 0.32 tons per year of CO and 0.09 tons per year of VOC would be removed at a total cost of $14,326 per ton of both pollutants removed, based on limited operation of 500 hours per year.

Keep in mind that normal operation for this unit will be testing and maintenance for less than one hour per week and results costs for the add- on controls would be much, much higher. Even when considering emergency operation for up to 500 hours per year, the cost for adding an oxidation catalyst to the emergency fire pump is considered economically infeasible; therefore, an oxidation catalyst for control of CO and VOC emissions from the emergency fire pump is not considered BACT. Additionally, since the emergency fire pump will typically operate for less than one hour during routine maintenance and testing, the emissions will be uncontrolled since it takes time for the catalyst to warm-up to optimal operating temperature; therefore, an oxidation catalyst is not an effective control technology.

Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel fire pump.

5.12.4.4.2 Combustion Control

Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

5.12.4.5 Step 5. Proposed VOC Emergency Diesel Fire Pump BACT Determination

Combustion control was selected as BACT for VOC for the emergency diesel fire pump; add-on controls are not practical on these small units with limited operation and economic impacts are high. The emergency diesel fire pump will be able to achieve 1.1 g/hp-hr of VOC emissions on an on-going basis.

5.12.5 BACT for Sulfuric Acid Mist – Emergency Diesel Fire Pump

The following sections outline the top-down steps for H_2SO_4 emissions from the emergency diesel fire pump.

5.12.5.1 Step 1-5 Identify, Rank and Select BACT

There are no add-on control technologies for controlling H_2SO_4 emissions from a diesel fire pump. As with the combustion turbine, using low sulfur fuel and controlling combustion is the only technologically feasible control option.

BACT is use of lower sulfur fuel and good combustion practices. This will achieve an emission rate of 0.02 tons per year of H_2SO_4 from the fire pump.

5.12.6 BACT for Greenhouse Gases – Emergency Diesel Fire Pump (Steps 1-5)

The emergency diesel fire pump is proposed to be used for no more than 500 hours per year. The design of the engine is dictated by the manufacturer, not by the end-user. As such, the Project is limited to commercially available options, which include those engines meeting EPA Tier 3 requirements.

Consistent with its rationale for the BACT determination for greenhouse gas emissions from the combustion turbine, BACT for the emergency diesel fire pump involves selection of the most efficient stationary emergency engine that can meet the facility's needs. Total greenhouse gas emissions from the emergency diesel fire pump are estimated at 80 tons CO_2e per year. These greenhouse gas emissions are also *de minimis* when compared to the turbine greenhouse gas emissions.

A Tier 3-certified engine is the most fuel-efficient option for these purposes. Further, because emissions of greenhouse gases are directly correlated to operation of the unit, BACT requires that the engine shall only be operated for maintenance, readiness testing, and during emergencies and other periods authorized by the permitting agency and/or the permit.

Operation of the emergency diesel fire pump will be limited by permit conditions for reliability-and maintenance related activities and the Owners will be required to keep records of the operation of the emergency diesel fire pump and its fuel usage. Therefore, the Owners believe no additional conditions are required to enforce this greenhouse gas BACT determination.

5.12.7 BACT for Opacity – Emergency Diesel Fire Pump

The following sections outline the top-down steps for opacity emissions from the emergency diesel fire pump.

5.12.7.1 Step 1. Identify Potential Control Strategies

Opacity is not a discrete pollutant and cannot be measured using mass emissions rate criteria (e.g., lb/hr). Therefore, a typical top-down BACT economic analysis that evaluated effectiveness on a $/ton basis cannot be conducted on opacity. Rather, the opacity BACT determination should focus on pollutants in the flue gas that contribute to opacity. These pollutants include PM, NO_x, SO_2, and H_2SO_4. BACT determinations have been done for PM, NO_x and H_2SO_4 for this emergency diesel fire pump. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low exhaust opacity.

5.12.7.2 Step 2. Identify Technically Feasible Control Technologies

The Owners have prepared a detailed BACT evaluation for pollutants that potentially contribute to opacity. Based on these BACT evaluations, the Owners have identified the following control technologies as technically feasible: SCR and combustion control for NO_x control; and low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. These technologies represent BACT for the criteria pollutants and will also minimize opacity.

5.12.7.3 Step 3. Rank the Technically Feasible Control Technologies

Based on these BACT evaluations, the Owners have ranked the following feasible control technologies for opacity (1) combustion control, (2) clean fuels. The Owners have determined that the use of low ash, low sulfur fuel and combustion control combine to rank as the top option for opacity control.

5.12.7.4 Step 4. Evaluate the Most Effective Control Technologies

The energy, environmental, and economic impacts of the feasible control technologies are described in their respective BACT analysis.

5.12.7.5 Step 5. Proposed Opacity BACT Determination

BACT for exhaust opacity will include the use of combustion control for NO_x control and the use of low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. The combination of these control technologies represents BACT for opacity.

5.13 BACT Analysis for Emergency Diesel Generator (P07)

Previously submitted BACT Sections, post application submittals, and updated references to the BACT analysis sections for the emergency diesel generator are presented in Table 5-41. *The updated emergency diesel generator BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.*

Table 5-41: Emergency Diesel Generator BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT

	Post application NTEC Response #18	Incorporated into Section 5.13.3
RBLC	Appendix D, Table D-5 December 2018 Submittal	Table D-5 Appendix D
	--	Table D-5 Addendum Appendix D
Economic Tables	Table 3 and Table 4 Post application NTEC Response #11	Appendix E
	Table 2a and Table 2b Post application NTEC Response #17	Appendix E

One 1,490 hp (1,112 kW) emergency diesel generator will be installed for the Project. The emergency diesel generator will be limited to 500 hours per year (100 hours per year for testing and maintenance purposes) and will utilize ultra-low sulfur transportation grade distillate fuel oil, with a sulfur content of no more than 0.0015 weight percent. The emergency diesel generator will comply with the applicable NSPS requirements. The RBLC has limited information on BACT conclusions for small engines such as the emergency diesel generator (Appendix D). The RBLC tables also show high variability for emission rates for each pollutant. For all pollutants, no add-on controls were listed because the add-on controls were determined to not be economically feasible due to engine size.

BACT can be no less stringent than the NSPS Subpart IIII limits, which are discussed in Section 4.2.5.

A cost difference between a Tier 2 and Tier 4 engine as well as the associated dollar per ton of controlled emissions was provided at the request of WDNR as part of the post application information requests. The analysis is provided in Appendix E.

5.13.1 BACT for Nitrogen Oxides – Emergency Diesel Generator

The following sections outline the top-down steps for NO_x emissions from the emergency diesel generator.

5.13.1.1 Step 1. Identify Potential Control Strategies

For an emergency diesel generator that only operates 500 hours per year for testing and maintenance, there are no controls that are available that would approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul an SCR catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an SCR system may be technically feasible.

5.13.1.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling NO_x emissions are evaluated for technical feasibility in the following sections.

5.13.1.2.1 SCR

The RBLC did not list any add-on control devices as BACT for the emergency diesel generator; however, an SCR may be available for this size of engine.

As a result, an SCR system is considered technically feasible for the emergency diesel generator.

5.13.1.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.

5.13.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible NO_x control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-42.

Table 5-42: Ranking of NO_x Control Technologies for the Emergency Diesel Generator

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
SCR	90	0.48
Combustion Control	Not applicable (baseline)	4.8

5.13.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.13.1.4.1 SCR

Energy and Environmental Impacts

Energy and environmental impacts for an SCR system are discussed in Section 5.1.4.1.

Economic Impacts

The capital costs and annualized costs associated with an SCR system for the emergency diesel generator is shown in Appendix E. The total capital investment of installing an SCR system on the emergency diesel generator is approximately $80,866. On an annual basis, the SCR system would cost approximately $46,681, which results in a cost per ton of NO_x removed of almost $14,592 while removing only 3.3 tons of NO_x per year, based on limited operation of 500 hours per year. Therefore, any control of NO_x by add-on controls would result in costs that would not be economical, even when considering a maximum emergency use of up to 500 hours per year. In reality, the cost per ton removed will be much less, knowing that this unit will only be tested for up to one hour per week. Additionally, since the emergency diesel generator will typically operate for less than one hour during routine maintenance and testing, the emissions will be uncontrolled since it takes time for the SCR to warm-up to optimal operating temperature; therefore, a SCR is not an effective control technology.

Therefore, an SCR is not proposed as BACT because it is not economically feasible for the emergency diesel generator.

5.13.1.4.2 Combustion Control

Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

5.13.1.5 Step 5. Proposed NO_x Emergency Diesel Generator BACT Determination

Combustion control was selected as BACT for NO_x for the emergency diesel generator; add-on controls are not practical on a unit this size, with limited operation, and the economic impacts are high. The emergency diesel generator will be able to achieve 4.8 g/hp-hr of NO_x emissions on an on-going basis.

5.13.2 BACT for Carbon Monoxide – Emergency Diesel Generator

The following sections outline the top-down steps for CO emissions from the emergency diesel generator.

5.13.2.1 Step 1. Identify Potential Control Strategies

For an engine that only operates 500 hours per year for testing and maintenance, there are no controls that are available that would even approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul the oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an oxidation catalyst may be technically feasible.

5.13.2.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling CO emissions are evaluated for technical feasibility in the following sections.

5.13.2.2.1 Oxidation Catalyst

The RBLC did not list any add-on control devices as BACT for the emergency diesel generator; however, an oxidation catalyst may be available for this small engine size.

As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel generator.

5.13.2.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.

5.13.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-43.

Table 5-43: Ranking of CO Control Technologies for the Emergency Diesel Generator

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Oxidation Catalyst	90	0.26
Combustion Control	Not applicable (baseline)	2.6

5.13.2.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.13.2.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.2.4.1.

Economic Impacts

Because the emergency diesel generator only operates for 500 hours per year for testing and maintenance, a cost analysis is not needed to show that the cost per ton of CO removed would be economically infeasible. The emergency diesel generator will only emit 2.15 tons per year of CO, based on the annual 500 operating hour limitation.

Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel generator.

5.13.2.4.2 Combustion Control

Combustion control is accomplished through operational control of the engine, therefore, there are no energy, environmental, or economic impacts associated with this control.

5.13.2.5 Step 5. Proposed CO Emergency Diesel generator BACT Determination

Combustion control was selected as BACT for CO for the emergency diesel generator; add-on controls are not practical on this small unit with limited operation and economic impacts are high. The emergency diesel generator will be able to achieve 2.6 g/hp-hr of CO emissions on an on-going basis.

5.13.3 BACT for Particulate Matter – Emergency Diesel Generator

The following sections outline the top-down steps for PM/PM_{10}/$PM_{2.5}$ emissions from the emergency diesel generator.

5.13.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas) for the emergency diesel generator. Vendors have stated there is no precedent for a particulate filter on an emergency diesel generator; therefore, a diesel particulate filter is considered experimental control technology not viable for the diesel generator.

No add-on controls were identified for significant removal of these pollutants from the engine's exhaust.

5.13.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for PM/PM_{10}/$PM_{2.5}$.

5.13.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible PM/PM_{10}/$PM_{2.5}$ control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-44.

Table 5-44: Ranking of PM/PM_{10}/$PM_{2.5}$ Control Technologies for the Emergency Diesel Generator

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Combustion Control	Not applicable (baseline)	0.15

5.13.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for PM/PM_{10}/$PM_{2.5}$

Since no add-on controls were identified, combustion control with low ash fuel was selected as BACT for PM/PM_{10}/$PM_{2.5}$ at an emission rate of 0.15 g/hp-hr for the emergency diesel generator.

5.13.4 BACT for Volatile Organic Compounds – Emergency Diesel Generator

The following sections outline the top-down steps for VOC emissions from the emergency diesel generator.

5.13.4.1 Step 1. Identify Potential Control Strategies

For an engine that only operates 500 hours per year for testing and maintenance, there are no controls that are available that would even approach being cost effective. In addition, the fuel oil that is combusted would quickly poison and/or foul the oxidation catalyst in a short amount of operating time. For the purposes of this BACT analysis, however it is assumed that an oxidation catalyst may be technically feasible.

5.13.4.2 Step 2. Identify Technically Feasible Control Technologies

The primary methods for controlling VOC emissions are evaluated for technical feasibility in the following sections.

5.13.4.2.1 Oxidation Catalyst

Although the RBLC did not list any add-on control devices as BACT for the emergency diesel generator, an oxidation catalyst may be available for this small engine.

As a result, an oxidation catalyst system is considered technically feasible for the emergency diesel generator.

5.13.4.2.2 Combustion Control

"Good combustion practices" include operational and design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion.

As a result, combustion control is considered baseline for the emergency diesel generator and is technically feasible.

5.13.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible VOC control technologies for the emergency diesel generator are ranked by control effectiveness in Table 5-45.

Table 5-45: Ranking of VOC Control Technologies for the Emergency Diesel Generator

Control Technology	Reduction (%)	Controlled Emission Level (g/hp-hr)
Oxidation Catalyst	20	0.26
Combustion Control	Not applicable (baseline)	0.32

5.13.4.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. These impacts are discussed below for each control technology.

5.13.4.4.1 Oxidation Catalyst

Energy and Environmental Impacts

Energy and environmental impacts for an oxidation catalyst are discussed in Section 5.4.4.1.

Economic Impacts

Because the emergency diesel generator will only operate 500 hours per year for testing and maintenance, a cost analysis is not needed to show that the cost per ton of VOC removed would not be economically feasible. The emergency diesel generator will only emit 0.26 tons per year of VOC, based on the annual 500 operating hour limitation.

Therefore, an oxidation catalyst is not proposed as BACT because it is not economically feasible for the emergency diesel generator.

5.13.4.4.2 Combustion Control

Combustion control is accomplished through operational control of the engines; therefore, there are no energy, environmental, or economic impacts associated with this control.

5.13.4.5 Step 5. Proposed VOC Emergency Diesel Generator BACT Determination

Combustion control was selected as BACT for VOC for the emergency diesel generator; add-on controls are not practical on these small units with limited operation and economic impacts are high. The emergency diesel generator will be able to achieve 0.32 g/hp-hr of VOC emissions for the generator on an on-going basis.

5.13.5 BACT for Sulfuric Acid Mist – Emergency Diesel Generator

The following sections outline the top-down steps for H_2SO_4 emissions from the emergency diesel generator.

5.13.5.1 Step 1-5 Identify, Rank and Select BACT

There are no add-on control technologies for controlling H_2SO_4 emissions from a diesel generator. As with the combustion turbine, using low sulfur fuel and controlling combustion is the only technologically feasible control option.

BACT is use of lower sulfur fuel and good combustion practices. This will achieve an emission rate of 6.9×10^{-4} tons per year of H_2SO_4 from the emergency diesel generator.

5.13.6 BACT for Greenhouse Gases – Emergency Diesel Generator (Steps 1-5)

The emergency diesel generator is proposed to be used for no more than 500 hours per year. The design of the engine is dictated by the manufacturer, not by the end-user. As such, the Project is limited to commercially available options, which include those engines meeting EPA Tier 2 requirements.

Consistent with its rationale for the BACT determination for greenhouse gas emissions from the combustion turbine, BACT for the emergency diesel generator involves selection of the most efficient stationary emergency diesel generator that can meet the facility's needs. Total greenhouse gas emissions from the emergency diesel generator are estimated at 841 tons CO_2e per year. These greenhouse gas emissions are also *de minimis* when compared to the turbine greenhouse gas emissions.

A Tier 2-certified engine is the most fuel-efficient option for these purposes. Further, because emissions of greenhouse gases are directly correlated to operation of the unit, BACT requires that the engine shall only be operated for maintenance, readiness testing, and during emergencies and other periods authorized by the permitting agency and/or the permit.

Because operation of the emergency diesel generator will be limited by permit conditions for reliability- and maintenance related activities and the Owners will be required to keep records of the operation of the emergency diesel generator and its fuel usage. Therefore, the Owners believe no additional conditions are required to enforce this greenhouse gas BACT determination.

5.13.7 BACT for Opacity – Emergency Diesel Generator

The following sections outline the top-down steps for opacity emissions from the emergency diesel generator.

5.13.7.1 Step 1. Identify Potential Control Strategies

Opacity is not a discrete pollutant and cannot be measured using mass emissions rate criteria (e.g., lb/hr). Therefore, a typical top-down BACT economic analysis that evaluated effectiveness on a $/ton basis cannot be conducted on opacity. Rather, the opacity BACT determination should focus on pollutants in the flue gas that contribute to opacity. These pollutants include PM, NO_x, SO_2, and H_2SO_4. BACT determinations have been done for PM, NO_x and H_2SO_4 for this emergency diesel generator. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low exhaust opacity.

5.13.7.2 Step 2. Identify Technically Feasible Control Technologies

The Owners have prepared a detailed BACT evaluation for pollutants that potentially contribute to opacity. Based on these BACT evaluations, the Owners have identified the following control technologies as technically feasible: SCR and combustion control for NO_x control; and low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. These technologies represent BACT for the criteria pollutants and will also minimize opacity.

5.13.7.3 Step 3. Rank the Technically Feasible Control Technologies

Based on these BACT evaluations, the Owners have ranked the following feasible control technologies for NO_x: (1) combustion control, (2) clean fuels. The Owners have determined that the use of low ash, low sulfur fuel and combustion control combine to rank as the top option for opacity control.

5.13.7.4 Step 4. Evaluate the Most Effective Control Technologies

The energy, environmental, and economic impacts of the feasible control technologies are described in their respective BACT analysis.

5.13.7.5 Step 5. Proposed Opacity BACT Determination

BACT for exhaust opacity will include the use of combustion control for NO_x control and the use of low ash, low sulfur fuel and combustion control for PM and H_2SO_4 control. The combination of these control technologies represents BACT for opacity.

5.14 BACT for Volatile Organic Compounds – Fuel Oil Storage Tanks (T01, T02, and T03)

Previously submitted BACT Sections and updated references to the BACT analysis sections for the fuel oil storage tanks are presented in Table 5-46. The updated fuel oil storage tank BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-46: Fuel Oil BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT December 2018 Submittal	5.0 BACT

The following sections outline the top-down BACT steps for emissions of VOC from the fuel oil storage tanks.

5.14.1 Steps 1, 2, and 3. Identify Potential Feasible Control Strategies and Rank Control Strategies

The Project will include three fuel oil (diesel) storage tanks: 180,000-gallon, 1,700-gallon, and 350-gallon. Diesel fuel has a very low vapor pressure and as such, controls that may be used on high vapor pressure liquids, such as floating roofs, are not as effective at reducing emissions. Fixed roof tanks are proposed for control of emissions from the fuel oil storage tanks.

5.14.2 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for VOC Emissions

The proposed BACT for the fuel oil storage tanks is the use of fixed roof tanks. Because emissions are extremely low from these sources, this is the only feasible and reasonable control for these small emission sources. Emissions will be less than 0.04 tons per year.

5.15 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Haul Road Fugitives (F01)

Previously submitted BACT Sections and updated references to the BACT analysis sections for the haul road fugitives are presented in Table 5-47. The updated haul road BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.

Table 5-47: Haul Road Fugitives BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT January 2021 Submittal	5.0 BACT
RBLC	Appendix D, Table D-2 January 2021 Submittal	Table D-9, Appendix D
	--	Table D-9 Addendum, Appendix D

Haul roads will be located onsite and delivery truck traffic will travel on paved roads. Emissions of particulate matter will be filterable only and speciated into PM, PM_{10}, and $PM_{2.5}$. However, control technologies will control all sizes of particulate.

5.15.1 Step 1: Identify Potential Control Strategies

In a review of the RBLC, the following control technologies for particulate emissions from roads were identified:

1. Chemical dust suppression and surfactant application,
2. Watering, sweeping and vacuuming,
3. Paving, and
4. Traffic and speed restrictions

5.15.2 Step 2: Identify Technically Feasible Control Technologies

All of the options listed, except chemical dust suppression and surfactant application, are potentially applicable control technologies considered technically feasible for the Project. Chemical dust suppression and surfactant application are generally used for unpaved surface and are considered infeasible for this Project as the facility roads will be paved.

5.15.3 Step 3: Rank the Technically Feasible Control Technologies

The third step in the BACT analysis is to rank the remaining control technologies in order of control effectiveness. Table 5-48 provides a listing of $PM/PM_{10}/PM_{2.5}$ control technologies by effectiveness.

Table 5-48: Efficiency Ranking of Particulate Control Technologies for Haul Roads

Control Technology	Approximate Control Efficiency (percent)
Water flushing followed by sweeping of paved roads	up to 96
Water flushing of paved roads	up to 69
Vacuum sweeping of paved roads	up to 58
Paving	--
Speed/traffic restrictions	--

Source: EPA Control of Open Fugitive Dust Sources

5.15.4 Step 4: Evaluate Most Effective Control Technologies

The fourth step in the BACT analysis is to evaluate the most effective control technology based on energy, environmental, and economic impacts. Based on a review of the RBLC, the implementation of a Fugitive Dust Control Plan (FDCP) is considered a control method accepted as BACT for particulate emissions from roads at similar facilities. No specific BACT emission limits associated with the previously mentioned control methods were obtained from the RBLC.

5.15.5 Step 5: Select BACT

The applicants propose to develop, maintain, and implement a FDCP as BACT for the paved roads.

5.16 BACT for Greenhouse Gases (GHG) and VOCs – Natural Gas and Fuel Oil Fugitives (F02)

Previously submitted BACT Sections, post application evaluations, and updated references to the BACT analysis sections for the natural gas and fuel oil fugitives are presented in Table 5-49. *The updated natural gas and fuel oil fugitives BACT analysis shows that the BACT determination in the original application and PSD permit remain valid.*

Table 5-49: Natural Gas and Fuel Oil Fugitives BACT Analysis References

Description	Previous Application Reference	December 2021 Submittal Location
BACT Analysis Steps 1 to 5	5.0 BACT January 2021 Submittal	5.0 BACT
	Post application BACT evaluation on "leak-proof" piping components WDNR Memorandum dated July 8, 2021	Incorporated into Section 5.0 BACT
RBLC	Table D-1, Appendix D January 2021 Submittal	Table D-8, Appendix D
	--	Table D-8 Addendum, Appendix D
Economic Tables	Appendix E Cost Evaluations January 2021 Submittal	Appendix E
	Cost Analysis Post application BACT evaluation on "leak-proof" piping components	Appendix E

The proposed project will include natural gas piping components from the natural gas line that will enter the Project site to provide gas for the combustion turbine, duct burner, natural gas heaters and auxiliary boiler. These natural gas piping components are potential sources of methane emissions due to emissions from valves, flanges, sampling connections and relief valves.

The proposed project will also include fuel oil piping components from the fuel oil line that will enter the Project site to provide fuel oil for the combustion turbine and duct burner. The emergency diesel fire pump and emergency diesel generator piping components will also have minimal fugitive emissions. These fuel oil piping components are potential sources of VOC emissions due to emissions from valves, flanges, sampling connections and relief valves.

Methane is not a VOC but is regulated as a GHG with a GWP of 25 when expressed as CO_2e. Evaporative emissions from fuel oil, such as xylene and benzene, are VOCs.

5.16.1 Step 1: Identify Potential Control Strategies

Greenhouse gas emissions (methane) and VOCs may leak out of certain components within the pipeline system, anywhere there is a connection, valve or flange. Per a review of the RBLC database (Appendix D), the following technologies were identified as potential control options for these piping fugitives:

- Implementation of leak detection and repair (LDAR) program - Instrument monitoring: using a handheld analyzer to determine if leaks exist
- Implementation of LDAR - Physical inspection: an audio/visual/olfactory (AVO) leak detection program
- Good operating processes
- Certified low-leaking valves

5.16.2 Step 2: Identify Technically Feasible Control Technologies

The use of instrument monitoring LDAR and remote sensing technologies are technically feasible for natural gas and fuel oil components. A LDAR program based on AVO monitoring is determined to be infeasible because the natural gas transmission pipeline that connects directly to the facility will not be odorized with mercaptan, the odorant typically added to distribution lines to allow for olfactory detection of any leaks without instrumentation. Since mercaptan is not present, inspections for gas leakage are accomplished by using leak detector equipment. These leak detection surveys with instrumentation are conducted at intervals as prescribed by applicable state and gas pipeline regulations. AVO inspections for fuel oil are technically feasible. Additionally, good operating practices and certified low-leaking values are also feasible for the natural gas and fuel oil fugitive emissions. Therefore, the instrument monitoring LDAR program, good operating practices, and certified low-leaking valves listed in Step 1 are technically feasible for natural gas. All listed control technologies in Step 1 are technically feasible for fuel oil.

5.16.3 Step 3: Rank the Technically Feasible Control Technologies

LDAR programs are used to inspect fugitive components to identify leaks either by using instruments or by physical inspections. Leaks identified by the inspections are then repaired within a specified time period, thus reducing the emissions.

The top-ranked control strategy is a LDAR program that utilizes instrument leak detection. Based on available data piping components are generally assigned control efficiencies ranging from 30 to 97 percent for valves, relief valves, and sampling connections (TCEQ, 2018).

The second-ranked control option involves implementation of a AVO leak detection program. Per Texas Commission on Environmental Quality (TCEQ) documentation of a control efficiency of 97 percent is generally assigned for a AVO program.

Certified low-leaking valves are a remaining control technology with 80 percent control of VOC and CO_2e.

Good operating processes are considered baseline for the purposes of this BACT analysis. Table 5-50 summarizes the control efficiencies for the various control technology options.

Table 5-50. GHG and VOC Technology Rankings for Natural Gas and Fuel Oil Fugitives

Rank	Control Technology	Percent Control
1	LDAR program – instrument monitoring	97%
2	LDAR program - AVO leak detection	97%
3	Certified low-leaking valves	80%
4	Good operating process	Not applicable (baseline)

Source: TCEQ, 2018

5.16.4 Step 4: Evaluate Most Effective Control Technologies

Since the uncontrolled VOC and CO_2e emissions from the natural gas and fuel oil piping represent less than 0.04 percent of the total site wide VOC emissions and less than 0.04 percent of the total site wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal additional VOC and CO_2e emission reductions over the baseline.

The economic impacts of installing a LDAR program for instrument monitoring was evaluated. Based on EPA data the estimated cost effectiveness of LDAR programs is shown below in Table 5-51 (EPA, 1992).

Table 5-51: Cost Effectiveness of LDAR Programs

Control	Annual Cost ($/year)	Cost Effectiveness – Mass ($/ton GHG)	Cost Effectiveness – CO_2e ($/ton CO_2e)
LDAR program – instrument monitoring	$76,389	$3,258	$130

The economic impacts of installing low-leaking valves were also evaluated. For the valves that are included in the natural gas and fuel oil piping components emissions unit (F02), the department (WDNR) determined that certified low-leaking valves cost would be $5,874 per ton of methane ($234.95 per ton CO_2e) and $29,826 per ton VOC removed. To provide a basis for determining economic feasibility for CO_2e, the cost of 1 ton of carbon credits in the California cap and trade program is approximately $19 per ton of CO_2e for the May 2021 auction. Because the control costs are above the levels that the WDNR considers to be economically feasible as BACT under PSD, certified low-leaking valves have been determined by the department to not be economically feasible

A detailed cost summary analysis is provided in Appendix E.

5.16.5 Step 5: Select BACT

Based on the top-down analysis for natural gas, an instrument monitoring LDAR program is BACT for natural gas components. Instrument monitoring LDAR program was also selected as BACT for fuel oil components.

Any GHG and VOC emissions from the piping components will be fugitive emissions. Fugitive emissions are, by their nature, very difficult to monitor directly, as they are not emitted from a discrete emission point. Therefore, the Owners propose the following compliance demonstrations, recordkeeping and monitoring requirements:

1. Conduct instrument monitoring inspections on piping components each calendar quarter to detect leaks of natural gas and fuel oil.
2. Keep a log of all the quarterly instrument monitoring inspections from piping components that are part of this Project.
3. Develop a Facility Leak Detection Plan

These proposed work practices are consistent with the BACT determinations identified above.

6.0 AIR DISPERSION MODELING

Summary: An updated air quality analysis was performed using WDNR's recently updated meteorological data and background concentrations. Section 6.0 replaces all previously submitted air dispersion modeling analyses. The SO_2 emission rates for modeling provided to WDNR as part of a data request response #7 is provided in Appendix F.

Since the Project is subject to PSD review, an air dispersion modeling analysis is required for each regulated NSR pollutant that exceeds its PSD significance level. According to the emission calculations for this Project, NO_x, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and CO_2e are subject to PSD review; as a result, an air quality analysis was performed for NO_x, CO, PM_{10}, and $PM_{2.5}$ using the EPA-approved American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD). Consistent with WDNR and EPA guidance, AERMOD modeling of PM, VOC, and CO_2e were not conducted, since there are no modeling thresholds for these pollutants.

A summary of the models, the modeling techniques, and modeling results for the Project are discussed in the following sections.

6.1 Air Dispersion Model

Air dispersion modeling was performed using the latest version of the AERMOD model (Version 21112). The AERMOD model is an EPA-approved, steady-state Gaussian air dispersion model that is designed to estimate downwind ground-level concentrations from single or multiple sources using detailed meteorological data. AERMOD is a model currently approved for industrial sources and PSD permits.

The WDNR requested that the Owners demonstrate regulatory compliance through the use of AERMOD. Major features of the AERMOD model are as follows:

- Plume rise, in stable conditions, is calculated using Briggs equations that consider wind and temperature gradients at stack top and half the distance to plume rise; in unstable conditions, plume rise is superimposed on the displacements by random convective velocities, accounting for updrafts and downdrafts due to momentum and buoyancy as a function of downwind distance for stack emissions.
- Plume dispersion receives Gaussian treatment in horizontal and vertical directions for stable conditions and non-Gaussian probability density function in vertical direction for unstable conditions.

- AERMOD creates profiles of wind, temperature, and turbulence, using all available measurement levels and accounts for meteorological data throughout the plume depth.
- Surface characteristics, such as Bowen ratio, albedo, and surface roughness length, may be specified to better simulate the modeling domain.
- Planetary Boundary Layers (PBL) such as friction velocity, Monin-Obukhov length, convective velocity scale, mechanical and convective height, and sensible heat flux may be specified.
- AERMOD uses a convective (based upon hourly accumulation of sensible heat flux) and a mechanical mixed layer height.
- AERMOD's terrain pre-processor (AERMAP) provides information for the advanced critical dividing streamline height algorithms and uses National Elevation Dataset (NED) to obtain elevations.
- AERMOD uses vertical and horizontal turbulence-based plume growth (from measurements and/or PBL theory) that varies with height and uses continuous growth functions.
- AERMOD uses convective updrafts and downdrafts in a probability density function to predict plume interaction with the mixing lid in convective conditions while using a mechanically mixed layer near the ground.
- Plume reflection above the lid is considered.
- AERMOD models impacts that occur within the cavity regions of building downwash via the use of the plume rise model enhancements (PRIME) algorithm, and then uses the standard AERMOD algorithms for areas without downwash.

Details of the AERMOD modeling options may be found in the User's Guide for AERMOD (EPA, 2021). The regulatory default option was selected for this analysis since it met the EPA guideline requirements and WDNR modeling guidance requirements.

The following default model options were used:

- Elevated Terrain Algorithms
- Stack-tip Downwash
- Gradual Plume Rise
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Default Vertical Potential Temperature Gradient

- Rural Dispersion

6.2 Model Parameters

Modeling runs were conducted at full load and partial loads of the combustion turbines to confirm that operation of the Project will not result in impacts greater than the NAAQS and PSD Class II Increments. The expected hourly emission rates and modeling parameters for the combustion turbine while combusting natural gas or fuel oil are shown in Table 6-1 and Table 6-2, respectively. These emission rates represent projected worst-case ambient conditions under various operating loads and include start-up and shutdown emissions. The annual emissions are based on worst-case annual emissions. Modeling of VOC and CO_2e will not be carried out because there are no modeling thresholds for these pollutants.

Table 6-1: Combustion Turbine Emissions and Modeling Parameters – Natural Gas Operation

Pollutant	Units[a]	Duct firing 100% Load	100% Load	75% Load	MECL Load	Start-up/ Shutdown
NO_x	lb/hr	33.46	26.55	20.56	12.44	200.00[b]
	tpy	255.61				
CO	lb/hr	15.28	12.12	9.39	5.68	7,190.00[b]
$PM_{10}/PM_{2.5}$	lb/hr	36.31	21.80	16.81	12.94	21.80
	tpy	162.80				
Stack Parameters						
Stack temperature (ºF)[a]		163.55	167.12	164.93	164.93	166.94
Exit velocity (ft/s)[a]		64.00	63.81	48.88	36.82	61.56
Stack height (feet)		190.0				
Stack diameter (feet)		21.28				

(a) lb/hr = pounds per hour, tpy = tons per year, ºF = degrees Fahrenheit, ft/s = feet per second, MECL = minimum emissions compliance load
(b) Maximum 1-hour start-up emissions (worst-case combustion turbine emissions during start-up)

Table 6-2: Combustion Turbine Emissions and Modeling Parameters – Fuel Oil Operation

Pollutant	Units[a]	Duct firing 100% Load	100% Load	75% Load	MECL Load	Start-up/ Shutdown
NO_x	lb/hr	72.68	51.55	41.04	31.10	510.00[b]
	tpy	255.61				
CO	lb/hr	11.06	7.85	6.25	15.78	16,860.00[b]
$PM_{10}/PM_{2.5}$	lb/hr	54.51	39.45	37.50	35.68	39.45
	tpy	162.80				
Stack Parameters						
Stack temperature (ºF)[a]		176.63	176.63	169.24	165.01	175.66
Exit velocity (ft/s)[a]		71.96	71.19	57.75	43.48	68.88
Stack height (feet)		190.0				
Stack diameter (feet)		21.28				

(a) lb/hr = pounds per hour, tpy = tons per year, ºF = degrees Fahrenheit, ft/s = feet per second, MECL = minimum emissions compliance load
(b) Maximum 1-hour start-up emissions (worst-case combustion turbine emissions during start-up)

The expected hourly emission rates and modeling parameters for the auxiliary equipment are shown in Table 6-3. Annual emissions for the auxiliary boiler and gas heaters were based on 8,760 hours of operation per year.

Table 6-3: Auxiliary Equipment Emissions and Modeling Parameters

Pollutant	Units[a]	Auxiliary Boiler	Natural Gas Heater #1	Natural Gas Heater #2
NO_x	lb/hr	1.10	0.49	0.49
	tpy	4.82	2.15	2.15
CO	lb/hr	0.37	0.82	0.82
$PM_{10}/PM_{2.5}$	lb/hr	0.75	0.07	0.07
	tpy	3.26	0.33	0.33
Stack Parameters				
Stack temperature (ºF)[a]		290.00	750.00	750.00
Exit velocity (ft/s)[a]		48.00	25.00	25.00
Stack height (feet)		110.00	15.00	15.00
Stack diameter (feet)		3.50	1.67	1.67

(a) lb/hr = pounds per hour, tpy = tons per year, ºF = degrees Fahrenheit, ft/s = feet per second

6.3 Haul Roads

The haul roads included in the model were laid out using the guidance from the March 2, 2012, EPA memo on the *Haul Road Workgroup Final Report* (EPA, 2012). The following parameters were used:

- Vehicle height of 12 feet

- Road width of 20 feet
- Top of plume height = 1.7 x vehicle height = 20.40 feet or 6.22 meters
- Volume source release height = 0.5 x top of plume height = 10.20 feet or 3.11 meters
- Width of plume = road width + 6 meters for two lane roadways = 39.69 feet or 12.10 meters
- Initial sigma z = top of plume / 2.15 = 9.49 feet or 2.89 meters
- Initial sigma y = width of plume / 2.15 = 18.46 feet or 5.63 meters
- Adjacent volume source spacing = sigma y x 2.15 = 39.69 feet or 12.10 meters

The calculated road emissions are included in Appendix C.

6.4 Modeling Methodology

The modeling methodology used for this analysis is summarized in the sections below.

6.4.1 Intermittent Emissions

Per WDNR guidance, the Owners propose to only model sources with continuous operation. Emission units that do not have a set operating schedule, operate for short periods of time during the year, and do not contribute to the normal operation of the facility were not included in modeling analysis. Therefore, the emergency diesel fire pump and emergency diesel generator are considered intermittent sources and were not included in the modeling analysis.

6.4.2 Emission Factors

Emissions factor (EMISFACT) modeling options in AERMOD allow a user to model emissions only when certain criteria are met. EMISFACT was not used for any Project sources. EMISFACT was used for the inventory sources where WDNR indicated it was appropriate, specifically for inventory source “UW-16” which operates only from October to April.

6.4.3 Rain Caps and Horizontal Stacks

If horizontal stacks or rain caps are present at the site, the restriction of vertical flow is accounted for through the use of the POINTCAP or POINTHOR keywords within the AERMOD input file. The POINTCAP and POINTHOR keywords were not used for any Project sources. The POINTHOR keyword was used for the Husky Superior inventory sources where WDNR indicated it was appropriate.

6.4.4 Good Engineering Practice Stack Height

Sources are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. As defined by the regulations, for stacks in existence on January 12, 1979 and with appropriate permits under 40 CFR Parts 51 and 52, GEP height is calculated as:

$$GEP = 2.5*H$$

Where,

H = the building height

For all other stacks, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

$$GEP = H + 1.5L$$

Where,

H = the building height; and

L = the lesser of the building height or the greatest crosswind distance of the building - also known as maximum projected width.

To meet stack height requirements, the point sources were evaluated in terms of the proximity to nearby structures. The purpose of this evaluation is to determine if the discharge from each stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. In EPA's 1985 *Guideline for Determination of Good Engineering Practice Stack Height*, EPA provides guidance for determining whether building downwash will occur. The downwash analysis was performed consistent with the methods prescribed in this guidance document.

Calculations for determining the direction-specific downwash parameters were performed using the most current version of the EPA's Building Profile Input Program – Plume Rise Model Enhancements, otherwise referred to as the BPIP-PRIME downwash algorithm (Version 04274). The BPIP-PRIME files are included in the electronic file transfer to the WDNR. After running the BPIP-PRIME model, it was determined that the GEP stack heights do not exceed the greater of 65 meters or the calculated GEP stack height.

The buildings are included in the model per the following WDNR guidance:

- If a building has multiple tiers, the structure was modeled as a single building with multiple tiers (wedding cake methodology).

- Structures that are less than four feet in height were not modeled.
- All structures that present a solid face from the ground to the top of the structure and that have angled corners were included.
- Structures off the ground were not included.
- Average roof heights were used for peaked or sloped tiers.
- Single, individual silos that are taller than they are wide were not included.
- Groupings of silos and large, wide circular grain bins using the eave height were included.

6.4.5 Receptor Grid

The overall purpose of the modeling analysis is to demonstrate that operation of the Project will not result in, or contribute to, concentrations above the NAAQS or PSD Class II Increments. Modeling runs were conducted using the AERMOD model in simple and complex terrain mode within a 20- by 20-kilometer Cartesian grid to determine the significant impact area for each pollutant. Based on guidance from WDNR, the grid incorporated the receptor spacing specified in Table 6-4. Receptors were also placed along the fence line boundary at a spacing of 25 meters.

Table 6-4: Receptor Spacing from Fence Line Boundary

Distance from Fence Line (kilometers)	Receptor Spacing (meters)
0 – 0.5	25
0.5 – 1	50
1 – 2	100
2 – 5	250
5 – 10	500

Source: WDNR, *Wisconsin Air Dispersion Modeling Guidelines*, 2018

A tight receptor grid provided by WDNR was included to incorporate the high terrain in Duluth as shown in Figure B-3, Appendix B.

Terrain elevations were incorporated into the model. The 1/3 arc second U.S. Geological Survey (USGS) NED data was used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) was used to develop the Universal Transverse Mercator (UTM) coordinates for this Project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but also a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 18081) utilized the electronic NED data to populate the model with receptor elevations.

6.4.6 Meteorological Data

AERMOD requires a preprocessor called AERMET to process meteorological data for 5 years from offsite locations to estimate the boundary layer parameters for the dispersion calculations. AERMET requires the input of surface roughness length, albedo, and Bowen ratio to define land surface characteristics for its calculations. WDNR provides AERMOD-ready processed meteorological data sets; therefore, the site characteristics (Bowen ratio, albedo, surface roughness) were completed by WDNR.

Surface air meteorological data from Sky Harbor Airport, in Duluth, Minnesota (WBAN ID 04919) and upper air data from Minneapolis, Minnesota (WBAN ID 94983) was used in the analysis. The most recent 5-year data set available covers the period of 2015 to 2018 and 2020. A profile base elevation of 186 meters was used in the model. The meteorological data used to develop these data sets has been analyzed by WDNR for data completeness, and these data sets have good data quality.

6.4.7 Land Use Parameters

USGS land cover data was used to determine the rural and urban land use percentages for a 3-kilometer area surrounding the Project site (Figure B-4, Appendix B). Land use categories I1, I2, C1, R2, and R3 were classified as urban land use categories (EPA, 2017). Less than 12 percent of the area surrounding the Nemadji River Site is classified as urban. Since the 3-kilometer area surrounding the Project is more than 50 percent rural, the rural dispersion coefficients option in the AERMOD model were selected.

6.4.8 Modeling Thresholds

The NAAQS, modeling/monitoring significance levels, and PSD Class II Increment thresholds for the modeled pollutants are shown in Table 6-5.

Table 6-5: NAAQS, Monitoring and Monitoring Significance Levels, and PSD Class II Increment

Pollutant	Averaging Period	Monitoring Significance Level	Modeling Significance Level	PSD Class II Increment	NAAQS
	micrograms per cubic meter (µg/m³)				
NO_x	Annual	14	1	25	100
	1-hour	NA	7.5	NA	188
CO	8-hour	575	500	NA	10,000
	1-hour	NA	2,000	NA	40,000
PM_{10}	Annual	NA	1	17	NA
	24-hour	10	5	30	150
$PM_{2.5}$	Annual	NA	0.2[b]	4	12
	24-hour	4[a]	1.2[b]	9	35

Source: WDNR *Wisconsin Air Dispersion Modeling Guidelines*, 2018
(a) The $PM_{2.5}$ 24-hour significant monitoring concentration vacated by the United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, is not considered valid in Wisconsin. However, representative local monitoring data is available for use.
(b) EPA Memorandum, 2018a, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program."

The modeled values were modeled using the appropriate form of the standard for each pollutant and averaging period. For significance modeling, all short-term and annual averaging periods were modeled with the impact shown in Table 6-6. For PSD Class II Increment, the short-term averaging periods were compared to the high second highest impacts, and the annual standards were compared to the first highest impacts. The NAAQS thresholds were modeled using the highs shown in Table 6-6 for each averaging period.

Table 6-6: Modeled Highs

Pollutant	Averaging Period	Significant Impact Level High	NAAQS Modeled High
NO_2	Annual	1st highest	1st highest
	1-hour	5-year average 1st high hour day	5-year average 8th high hour day
CO	8-hour	1st highest	High 2nd highest
	1-hour	1st highest	High 2nd highest
PM_{10}	Annual	1st highest	NA
	24-hour	1st highest	6th highest in 5 years
$PM_{2.5}$	Annual	5-year average year	5-year average year
	24-hour	5-year average 1st high day	5-year average 8th high day

Source: WDNR, *Wisconsin Air Dispersion Modeling Guidelines*, 2018

6.4.9 $PM_{2.5}$ Significant Impact Level Justification

The United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, vacated and remanded portions of the EPA rule establishing significant impact levels for $PM_{2.5}$. An analysis was performed to determine whether the vacated $PM_{2.5}$ significant impact levels are justified for this area.

The data that is collected by the monitors is available on the EPA website (http://www.epa.gov/airdata/). The most representative monitor for the 24-hour and annual $PM_{2.5}$ background concentrations is a monitor located at 720 North Central Avenue in Duluth, Minnesota (Air Quality System [AQS] ID: 27-137-7554). This is the closest operating $PM_{2.5}$ monitor and is most representative of the site. This monitor is located approximately 9 kilometers northwest from the Project site. The difference between the representative monitor value and the NAAQS standard (for both the 24-hour and annual standards) is sufficiently greater than the $PM_{2.5}$ significant impact level. Therefore, the use of $PM_{2.5}$ significant impact level is justified for this area, as demonstrated in Table 6-7.

Table 6-7: Duluth $PM_{2.5}$ Monitor (AQS ID: 27-137-7554)

Parameter	$PM_{2.5}$ 24-Hour Average	$PM_{2.5}$ Annual Average
	micrograms per cubic meter (μg/m³)	
2018-2020 design value[1]	16.0	5.3
NAAQS[2]	35.0	12.0
Difference NAAQS minus design value	19.0	6.7
PSD Class II significant impact level[3]	1.2	0.2

Source:
(1) EPA, http://www.epa.gov/airdata/, accessed 2021
(2) Title 40 CFR Part 50
(3) EPA Memorandum, 2018a, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program."

6.4.10 Ambient Monitoring

The modeling analysis for emission sources for the Project will also address the pre-construction monitoring provision of the PSD regulations (EPA 1987). The regulations specify monitoring *de minimis* levels for each PSD pollutant that, if exceeded, trigger the requirement to perform 1 year of pre-construction ambient air monitoring. If any predicted concentrations reach or exceed the monitoring *de minimis* levels, the Owners will consult with the WDNR to determine if pre-construction ambient air monitoring will be required. If modeled values exceed their respective monitoring *de minimis* values, the Owners will request a waiver to use local ambient monitoring data to fulfill the pre-construction monitoring provisions of the PSD regulations or develop an acceptable monitoring plan at that time. For any impacts predicted to be below the monitoring *de minimis* levels, the Owners will request an exemption from pre-construction ambient air monitoring, given that representative monitors in the area may be used for appropriate background concentrations.

6.4.11 NAAQS and PSD Class II Increment Analysis

When the maximum impacts exceed the significant impact level for any pollutant and averaging time, then a refined modeling analysis is required. The inventories of sources within the radius of impact were developed in accordance with applicable EPA guidance and obtained from the WDNR and Minnesota Pollution Control Agency. For the NAAQS and PSD Class II Increment analysis, all stationary sources identified by WDNR and Minnesota Pollution Control Agency that emit pollutants subject to this analysis and are located within the radius of impact were addressed.

Background air quality concentrations (as described in Section 6.4.12) were added to model-predicted concentrations for comparison to the NAAQS. If the refined analysis does not result in any concentrations above the NAAQS or PSD Class II Increments, no further modeling was conducted.

6.4.12 Background Air Quality

As stated previously, if any pollutant exceeds its respective PSD significance level, a refined analysis (cumulative analysis) was performed for that pollutant and averaging period. The analysis was used to determine compliance with the PSD Class II Increments and the NAAQS. The NAAQS are set up to protect the air quality for all sensitive populations, and attainment is determined by the comparison to the NAAQS thresholds. As such, there are existing concentrations of each criteria pollutant that are present in ambient air that must be included in an analysis to account for items, such as mobile source emissions, that are not already accounted for in the model. Monitored ambient emission levels were added to the modeled ground level impacts to account for these sources.

Regional background values were obtained from the WDNR *Guidance on Background Concentrations* memo (WDNR, 2021) that lists values for both “low” and “high” background categories. The Project is located in an area categorized as a “high” background area; therefore, the “high” background values were used for each pollutant that requires a refined analysis. The values listed in Table 6-8 were used as background levels and were added to the modeled impacts for each pollutant if NAAQS modeling is required.

Table 6-8: Background Concentrations

Pollutant	Averaging Period	Background Concentration (micrograms per cubic meter)
NO_2	Annual	HROFDY & MONTH[a]
	1-hour	HROFDY & MONTH[a]
CO	8-hour	916.8
	1-hour	1,196.0
PM_{10}	24-hour	33.1
$PM_{2.5}$	Annual	8.0
	24-hour	20.8

Source: WDNR, *Guidance on Air Quality Background Concentrations*, 2021
(a) Hour of day and monthly values are provided in the WDNR background guidance memo

6.4.13 NO_2 Modeling – Multi-Tiered Screening Approach

The AERMOD model gives the emission results for all pollutants, including NO_x. However, impacts of NO_2 must be examined for comparison to the NAAQS, PSD Class II Increments, and significance values. The EPA has a three-tier approach to modeling NO_2 concentrations:

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default NO_2/NO_x ratio
- Tier III – case-by-case detailed screening methods, such as the Ozone Limiting Method (OLM) or Plume Volume Molar Ratio Method (PVMRM)

Tier II of the Ambient Ratio Method (ARM2) uses a minimum and maximum ratio that varies based on the modeled level of NO_x. For the 1-hour modeled results, the default minimum and maximum ratios of 0.5 and 0.9, respectively, were applied to determine the predicted ground-level concentration of NO_2. For the annual modeled results, NO_x was assumed to be equal to NO_2 (Tier I).

6.5 Significance Model Results

Significance modeling was performed for NO_2, CO, PM_{10}, $PM_{2.5}$, and SO_2 for the appropriate emission sources. The modeled impacts are shown in Table 6-9 below.

Table 6-9: Maximum Modeled Concentrations for Significance Modeling.

Pollutant	Averaging Period	UTM Coordinates[a]		Year	Predicted Concentration	Modeling Significance Level[1]	Monitoring De Minimis Level[2]
		Easting (meters)	Northing (meters)		micrograms per cubic meter (µg/m³)		
NO_2	Annual	572,555.5	5,170,865.2	2016	2.9	1	14
	1-hour	568,000.0	5,183,000.0	5 years	162.5[b]	7.5	NA
CO	8-hour	572,900.0	5,171,475.0	2015	2,329.7	500	575
	1-hour	573,025.0	5,171,450.0	2015	5,252.7	2,000	NA
PM_{10}	Annual	572,769.1	5,171,086.5	2018	7.0	1	NA
	24-hour	572,808.9	5,171,122.0	2020	25.8	5	10
$PM_{2.5}$	Annual	572,791.2	5,171,106.1	2015	0.61[c]	0.2[e]	NA
	24-hour	572,300.0	5,170,725.0	2018	6.5[d]	1.2[e]	4[f]

Sources: WDNR, *Wisconsin Air Dispersion Modeling Guidelines*, 2018
(a) UTM = Universal Transverse Mercator: NAD83.
(b) ARM2 methodology was applied to the model.
(c) Impact represents primary and secondary annual $PM_{2.5}$ (0.6 $\mu g/m^3$+ 0.01 $\mu g/m^3$)
(d) Impact represents primary and secondary 24-hour $PM_{2.5}$ (6.3 $\mu g/m^3$+ 0.19 $\mu g/m^3$)
(e) EPA Memorandum, 2018a, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program."
(f) The $PM_{2.5}$ 24-hour significant monitoring concentration vacated by the United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, is not considered valid in Wisconsin. However, representative local monitoring data is available for use.

6.5.1 NO_2 Significance Results

After examining the modeling results, it was determined that exceedances of the annual and 1-hour NO_2 modeling significance level occurred, and that refined modeling will be required. The annual predicted impacts were lower than the ambient air monitoring *de minimis* level and therefore no pre-construction ambient monitoring is proposed for NO_2.

6.5.2 CO Significance Results

After examining the modeling results, it was determined that exceedances of the 8-hour or 1-hour CO modeling significance level occurred, and that refined modeling will be required. The 8-hour predicted impacts were greater than the ambient air monitoring *de minimis* level and therefore pre-construction ambient monitoring must be considered for CO. The Owners request that existing monitoring data from the Anoka County Airport monitor located in Blaine, Minnesota (AQS ID: 27-003-1002) be used for existing ambient levels of CO in the area.

6.5.3 PM_{10}/$PM_{2.5}$ Significance Results

After examining the modeling results, it was determined that exceedances of the 24-hour and annual PM_{10} and 24-hour and annual $PM_{2.5}$ modeling significance level occurred, and that refined modeling will be required.

The 24-hour predicted impacts were greater than the $PM_{2.5}$ ambient air monitoring *de minimis* levels and therefore pre-construction ambient monitoring must be considered for $PM_{2.5}$. The Owners request that existing monitoring data from the 720 North Central Avenue monitor located in Duluth, Minnesota (AQS ID: 27-137-7554) be used for existing ambient levels of $PM_{2.5}$ in the area.

The 24-hour predicted impacts were greater than the PM_{10} ambient air monitoring *de minimis* levels and therefore pre-construction ambient monitoring must be considered for PM_{10}. The Owners request that existing monitoring data from the 37th Avenue West and Oneota Street monitor located in Duluth, Minnesota (AQS ID: 27-137-0032) be used for existing ambient levels of PM_{10} in the area.

6.6 PSD Class II Increment Modeling

Refined modeling was performed for NO_2, PM_{10}, and $PM_{2.5}$ to demonstrate compliance with the PSD Class II Increments.

All Project emission sources and all inventory sources (provided by WDNR and Minnesota Pollution Control Agency) were included in the modeling analysis.

There were no modeled PSD Class II Increment exceedances for NO_2, PM_{10}, and $PM_{2.5}$ as shown in Table 6-10. Therefore, the Project will be in compliance with the Class II PSD Increment.

Table 6-10: Maximum Modeled Concentrations for Increment Modeling

Pollutant	Averaging Period	UTM Coordinates[a]		Year	Predicted Concentration	PSD Class II Increment
		Easting (meters)	Northing (meters)		micrograms per cubic meter (µg/m^3)	
NO_2	Annual	570,600.0	5,170,800.0	2017	8.4	25
PM_{10}	Annual	572,769.1	5,171,086.5	2018	7.1	17
	24-hour	572,808.9	5,171,122.0	2020	23.9	30
$PM_{2.5}$	Annual	572,791.2	5,171,106.1	2015	0.61[b]	4
	24-hour	573,300.0	5,171,050.0	2017	5.3[c]	9

Source: Title 40 CFR 52.21(c).
(a) UTM = Universal Transverse Mercator: NAD83
(b) Impact represents primary and secondary annual $PM_{2.5}$ (0.60 µg/m^3 + 0.01 µg/m^3)
(c) Impact represents primary and secondary 24-hour $PM_{2.5}$ (5.1 µg/m^3+ 0.19 µg/m^3)

6.7 NAAQS Modeling

Refined modeling was performed for NO_2, CO, PM_{10}, and $PM_{2.5}$ for all Project emission sources and all inventory sources (provided by WDNR and Minnesota Pollution Control Agency).

The modeling results showed that the Project will not contribute to any NAAQS exceedance for the pollutants and averaging periods modeled. Therefore, the Project will be in compliance with the NAAQS. The NAAQS analysis modeling results are shown in Table 6-11.

Table 6-11: Maximum Modeled Concentrations for NAAQS Modeling

Pollutant and Averaging Period		UTM Coordinates[a] Easting (meters)	UTM Coordinates[a] Northing (meters)	Year	Predicted Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)
NO_2	Annual	570,600.0	5,170,800.0	2016	--[b]	--[b]	52.5	100
	1-hour	571,500.0	5,186,000.0	5 years	--[b]	--[b]	181.9[c]	188
CO	8-hour	573,300.0	5,171,075.0	2017	1,903.3	916.8	2,820.13	10,000
	1-hour	572,875.0	5,171,525.0	2015	4,954.9	1,196.0	6,150.93	40,000
PM_{10}	24-hour	572,808.9	5,171,122.0	2015	19.7	33.1	52.8	150
$PM_{2.5}$	Annual	570,000.0	5,175,250.0	5 years	0.93[d]	8.0	8.93	12
	24-hour	570,000.0	5,175,250.0	5 years	5.3[e]	20.8	26.1	35

Source: Title 40 CFR Part 50
(a) UTM = Universal Transverse Mercator: NAD83
(b) HROFDY & MONTH background data used; therefore, the modeled impact is presented as project impacts and background combined.
(c) ARM2 methodology was applied to the model.
(d) Impact represents primary and secondary annual $PM_{2.5}$ (0.92 µg/m³+ 0.01 µg/m³)
(e) Impact represents primary and secondary 24-hour $PM_{2.5}$ (5.1 µg/m³+ 0.19 µg/m³)

6.8 PSD Class I Increment Screening Analysis

Under the PSD program, Class I areas are protected more stringently than under the NAAQS. Class I areas include national parks, wilderness areas, and other areas of special national and cultural significance.

There are four Class I areas that are within 300 kilometers of the Nemadji River Site

- Rainbow Lake Wilderness, Wisconsin (60 kilometers)
- Boundary Waters Canoe Area Wilderness, Minnesota (126 kilometers)
- Voyageurs National Park, Minnesota (182 kilometers)
- Isle Royale National Park, Michigan (237 kilometers)

There is also one non-Federal Class I area that is within 300 kilometers of the Project, Forest County Potawatomi Community Reservation, Wisconsin (261 kilometers).

Areas that have submitted requests to change the air quality status from Class II to Class I but whose request has yet to be granted were not evaluated for this Project.

The locations of the Project site and the Class I areas are shown in Figure B-5, Appendix B.

An assessment of air quality impacts at Class I areas was performed to demonstrate that the operation of the Project will not result in, or contribute to, concentrations above the PSD Class I Increment threshold. A screening analysis to determine if further analysis is required was performed for the four Class I areas and one non-Federal Class I area. The Class I Increment screening will be analyzed with AERMOD at a 50-kilometer distance from the Project by placing an arc of receptors extending 45 degrees (+/-) from the line connecting the Project and the Class I area. One Class I screening model that combined all Class I receptor arcs into one receptor grid was run for this analysis.

The AERMOD modeled impacts in comparison to the Class I significance thresholds are shown in Table 6-12. Based on the analysis, it was determined that the impacts from the Project will not significantly impact the PSD Class I Increment at the surrounding Class I areas and does not require further analysis.

Table 6-12: Class I Modeled Screening Impacts and Class I Significant Impact Level

Pollutant	Averaging Time	Maximum Modeled Concentration	Class I Significant Impact Level[1]
		micrograms per cubic meter ($\mu g/m^3$)	
NO_2[a]	Annual	0.03	0.1
PM_{10}	24-hour	0.3	0.3
	Annual	0.02	0.2
$PM_{2.5}$	24-hour	0.27[b]	0.27[2]
	Annual	0.02[c]	0.05[2]

Sources:
(1) EPA. Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR) Proposed Rulemaking, July 23, 1996. (61 FR 38249).
(2) EPA Memorandum, 2018a, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program."
(a) Modeled as NO_x.
(b) Impact represents primary and secondary 24-hour $PM_{2.5}$ (0.265 $\mu g/m^3$ + 0.0127 $\mu g/m^3$)
(c) Impact represents primary and secondary annual $PM_{2.5}$ (0.02 $\mu g/m^3$+ 0.0006 $\mu g/m^3$)

6.9 Secondary Formation Analysis

An analysis of the impact of secondary formation of ozone (NO_x and VOC) and $PM_{2.5}$ (NO_x and SO_2) was performed. The NAAQS and modeling significance level threshold for ozone and $PM_{2.5}$ are shown in Table 6-13.

Table 6-13: NAAQS and Modeling Significance Levels

Pollutant	Averaging Period	Modeling Significance Level[1,a]	NAAQS[2,a]
Ozone	8-hour	1.0 ppb	0.07 ppm (70 ppb)
$PM_{2.5}$	Annual	0.2 µg/m³	12 µg/m³
	24-hour	1.2 µg/m³	35 µg/m³

Source:
(1) EPA Memorandum, 2018, "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program."
(2) Title 40 CFR Part 50.
(a) ppb = parts per billion; ppm = parts per million; micrograms per cubic meter = µg/m³.

In April 2019, the EPA provided *Guidance on the Development of Modeled Emission Rates for Precursors (MERPS) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (the Guidance) in final form. The MERPS methodology was used to satisfy the compliance demonstration requirements for both ozone and secondary $PM_{2.5}$ for PSD purposes. The Tier 1 assessment in the Guidance uses existing empirical relationships between precursors and secondary impacts based on modeling performed by the EPA. MERPs were used to describe an emission rate of a precursor that is expected to result in a change in ambient ozone or $PM_{2.5}$ that would be less than a specific air quality concentration threshold for ozone or $PM_{2.5}$ to determine whether an impact causes or contributes to a violation of the NAAQS for ozone or $PM_{2.5}$.

6.9.1 Secondary $PM_{2.5}$ Formation Analysis

The NO_x (269.0 tons per year) emissions from the Project are below the lowest MERP values for the daily and annual $PM_{2.5}$ from the NO_x precursor for the Upper Midwest climate zone shown in Table 4-1 of the Guidance. The SO_2 (29.0 tons per year) emissions from the Project are below the lowest MERP value for the daily and annual $PM_{2.5}$ from the SO_2 precursor for the Upper Midwest climate zone shown in Table 4-1 of the Guidance. Based on these comparisons it was determined that it was appropriate to use the Upper Midwest climate zone data for the $PM_{2.5}$ significant impact level, Class II Increment, and NAAQS analysis.

For the Class I Increment analysis it was determined that it was more appropriate to use a specific hypothetical source in the same region and geographic area for comparison. Therefore, an analysis was performed to determine the most relevant hypothetical source.

Next, the NO_x and SO_2 precursor contributions to the daily and annual average $PM_{2.5}$ were considered together to determine if the Project's air quality impact of $PM_{2.5}$ would exceed the $PM_{2.5}$ significant impact level, Class II Increment, Class I Increment, and NAAQS.

6.9.1.1 Daily $PM_{2.5}$ Source Impact Analysis (µg/m³)

The secondary $PM_{2.5}$ impacts were expressed in µg/m³ to add to the primary $PM_{2.5}$ AERMOD results to obtain the overall $PM_{2.5}$ impacts. Using the Project emissions and Upper Midwest air quality impact information the source nitrate and sulfate daily impact is calculated as follows:

$$Nitrate\ Impact = \left(1.2\ \frac{\mu g}{m3} * \frac{269.0\ tpy}{2{,}963\ tpy}\right) = 0.11\ \frac{\mu g}{m3}$$

$$Sulfate\ Impact = \left(1.2\ \frac{\mu g}{m3} * \frac{29.0\ tpy}{454\ tpy}\right) = 0.08\ \frac{\mu g}{m3}$$

Therefore, the total daily secondary $PM_{2.5}$ impact is:

$$Total\ Daily\ Secondary\ PM2.5\ Impact = \left(0.11\ \frac{\mu g}{m3} +\ 0.08\ \frac{\mu g}{m3}\right) = 0.19\ \frac{\mu g}{m3}$$

6.9.1.1.1 Daily $PM_{2.5}$ – Class II Significant Impact Level

When the Project source primary impact (from AERMOD) and daily secondary impacts (from MERP equation) are added together the total impacts are greater than the daily $PM_{2.5}$ Class II significant impact level value of 1.2 µg/m³ as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(6.3\ \frac{\mu g}{m3} +\ 0.19\ \frac{\mu g}{m3}\right) = 6.5\ \frac{\mu g}{m3}$$

6.9.1.1.2 Daily $PM_{2.5}$ – Class II Increment

When the Project source primary impact (from AERMOD) and daily secondary impacts (from MERP equation) are added together the total impacts are less than the daily $PM_{2.5}$ Class II Increment value of 9.0 µg/m³ as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(5.1\ \frac{\mu g}{m3} +\ 0.19\ \frac{\mu g}{m3}\right) = 5.3\ \frac{\mu g}{m3}$$

6.9.1.1.3 Daily $PM_{2.5}$ – NAAQS

When the Project source primary impact (from AERMOD), background value, and daily secondary impacts (from MERP equation) are added together the total impacts are less than the daily $PM_{2.5}$ NAAQS value of 35 µg/m^3 as shown below.

$$Primary\ PM2.5\ Impact + background + Secondary\ PM2.5\ Impact = \left(5.1\ \frac{\mu g}{m3} + 20.8\ \frac{\mu g}{m3} + \ 0.19\ \frac{\mu g}{m3}\right) = 26.1\ \frac{\mu g}{m3}$$

6.9.1.2 Annual $PM_{2.5}$ Source Impact Analysis (µg/m^3) – Class II Significant Impact Level

The secondary $PM_{2.5}$ impacts were expressed in µg/m^3 to add to the primary $PM_{2.5}$ AERMOD results to obtain the overall $PM_{2.5}$ impacts. Using the Project emissions and Upper Midwest air quality impact information the annual source nitrate and sulfate impact is calculated as follows:

$$Nitrate\ Impact = \left(0.2\ \frac{\mu g}{m3} * \frac{269.0\ tpy}{10{,}011\ tpy}\right) = 0.01\ \frac{\mu g}{m3}$$

$$Sulfate\ Impact = \left(0.2\ \frac{\mu g}{m3} * \frac{29.0\ tpy}{2{,}522\ tpy}\right) = 0.002\ \frac{\mu g}{m3}$$

Therefore, the total annual secondary $PM_{2.5}$ impact is:

$$Total\ Annual\ Secondary\ PM2.5\ Impact = \left(0.01\ \frac{\mu g}{m3} + \ 0.002\ \frac{\mu g}{m3}\right) = 0.01\ \frac{\mu g}{m3}$$

6.9.1.2.1 Annual $PM_{2.5}$ – Class II Significant Impact Level

When the Project source primary impact (from AERMOD) and secondary impacts (from MERP equation) are added together the total impacts are greater than annual $PM_{2.5}$ Class II significant impact level value of 0.2 µg/m^3 as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(0.60\ \frac{\mu g}{m3} + \ 0.01\ \frac{\mu g}{m3}\right) = 0.61\ \frac{\mu g}{m3}$$

6.9.1.2.2 Annual $PM_{2.5}$ – Class II Increment

When the Project source primary impact (from AERMOD) and annual secondary impacts (from MERP equation) are added together the total impacts are less than the annual $PM_{2.5}$ Class II Increment value of 4.0 µg/m^3 as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(0.60\ \frac{\mu g}{m3} + \ 0.01\ \frac{\mu g}{m3}\right) = 0.61\ \frac{\mu g}{m3}$$

6.9.1.2.3 Annual $PM_{2.5}$ – NAAQS

When the Project source primary impact (from AERMOD), background value, and annual secondary impacts (from MERP equation) are added together the total impacts are less than the annual $PM_{2.5}$ NAAQS value of 12 μg/m^3 as shown below. Further analysis demonstrated that cumulative impacts from all NSG sources are less than the significant impact level for all modeled NAAQS exceedances.

$$Primary\ PM2.5\ Impact + background + Secondary\ PM2.5\ Impact = \left(0.92\ \frac{\mu g}{m3} + 8.0\ \frac{\mu g}{m3} + \ 0.01\ \frac{\mu g}{m3}\right) = 8.93\ \frac{\mu g}{m3}$$

6.9.1.3 Class I Daily and Annual $PM_{2.5}$

For the Class I analysis it was determined that it was more appropriate to use a specific hypothetical source in the same region and geographic area for comparison. Therefore, an analysis was performed to determine the most relevant hypothetical source.

6.9.1.3.1 Hypothetical $PM_{2.5}$ Source Impact Analysis

The Project is not located in an area with complex terrain and is not located close to large sources of pollutants that would impact atmospheric chemistry or meteorology (predominately rural area). Nearby hypothetical sources located in Wisconsin and Minnesota were identified and are shown in Table 6-14. According to the distance analysis, the closest hypothetical source is the St. Louis County source (137.8 kilometers away). The St. Louis County source surrounding terrain is representative of the Project site and the source is in a rural area similar to the Project location. A review of the data indicates that the St. Louis County source is representative of this Project.

Table 6-14: Hypothetical Source Review

County	County	Max Nearby Terrain (meters)	Max Nearby Urban (%)	Distance from Project Site (kilometers)
St Louis	Minnesota	431	2.8	137.8
Rusk	Wisconsin	410	2.3	156.5
Dakota	Minnesota	292	52.4	233.3
Wadena	Minnesota	420	2.2	234.5
Shawano	Wisconsin	237	32.2	365.5

Source: EPA MERPS View Qlik (Accessed October 2021)

Table 6-15 lists the values for the St. Louis County source for the respective emission rates and stack height combination. Project SO_2 and NO_x emissions are each less than 500 tons per year; therefore, the hypothetical 500 ton per year source was selected. Most of the emissions from project are emitted from a stack height above 50 meters; therefore, the 90-meter stack source was selected. These values were used to calculate the additive secondary impacts for Class I PSD Increment daily and annual $PM_{2.5}$.

Table 6-15: Hypothetical St. Louis County Source Table Values

Metric	Emissions (tons per year)	Stack Height (meters)	Distance (kilometers)[a]	Concentration (µg/m³)[b]
Annual $PM_{2.5}$ SO_2	500	90	60	0.003108
Daily $PM_{2.5}$ SO_2	500	90	60	0.0812
Annual $PM_{2.5}$ NO_x	500	90	60	0.00071
Daily $PM_{2.5}$ NO_x	500	90	60	0.0149

Source: EPA MERPS View Qlik (Accessed November 2021)
(a) The analysis was performed using the distance values associated to the nearest Class I area (most conservative), since Rainbow Lake Wilderness is located 60 kilometers from the Project.
(b) µg/m³ = micrograms per cubic meter

6.9.1.3.2 Daily Class I $PM_{2.5}$ Source Impact Analysis (µg/m³)

The secondary $PM_{2.5}$ impacts were expressed in µg/m³ to add to the primary $PM_{2.5}$ AERMOD results to obtain the overall $PM_{2.5}$ impacts. Using the Project emissions and air quality impact information from St. Louis County Source the source nitrate and sulfate daily impact is calculated as follows:

$$Nitrate\ Impact = \left(269.0\ tpy * \frac{0.0149\ \frac{\mu g}{m3}}{500\ tpy}\right) = 0.0080\ \frac{\mu g}{m3}$$

$$Sulfate\ Impact = \left(29.0\ tpy * \frac{0.0812\ \frac{\mu g}{m3}}{500\ tpy}\right) = 0.0047\ \frac{\mu g}{m3}$$

Therefore, the total daily secondary $PM_{2.5}$ impact is:

$$Total\ Daily\ Secondary\ PM2.5\ Impact = \left(0.0080\ \frac{\mu g}{m3} + 0.0047\ \frac{\mu g}{m3}\right) = 0.0127\ \frac{\mu g}{m3}$$

6.9.1.3.3 Daily $PM_{2.5}$ – Class I Increment

When the Project source primary impact (from AERMOD) and daily secondary impacts (from MERP equation) are added together the total impacts are less than the daily $PM_{2.5}$ Class I Increment value of 0.27 µg/m³ as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(0.265\ \frac{\mu g}{m3} + 0.0127\ \frac{\mu g}{m3}\right) = 0.278\ \frac{\mu g}{m3}$$

6.9.1.3.4 Annual Class I $PM_{2.5}$ Source Impact Analysis (µg/m³)

Using the Project emissions and air quality impact information from St. Louis County Source the source nitrate and sulfate annual impact is calculated as follows:

$$Nitrate\ Impact = \left(269.0\ tpy * \frac{0.00071\ \frac{\mu g}{m3}}{500\ tpy}\right) = 0.0004\ \frac{\mu g}{m3}$$

$$Sulfate\ Impact = \left(29.0\ tpy * \frac{0.003108\ \frac{\mu g}{m3}}{500\ tpy}\right) = 0.0002\ \frac{\mu g}{m3}$$

Therefore, the total annual secondary $PM_{2.5}$ impact is:

$$Total\ Annual\ Secondary\ PM2.5\ Impact = \left(0.0004\ \frac{\mu g}{m3} +\ 0.0002\ \frac{\mu g}{m3}\right) = 0.0006\ \frac{\mu g}{m3}$$

6.9.1.3.5 Annual $PM_{2.5}$ – Class I Increment

When the Project source primary impact (from AERMOD) and annual secondary impacts (from MERP equation) are added together the total impacts are less than the annual $PM_{2.5}$ Class I Increment value of 0.05 µg/m³ as shown below.

$$Primary\ PM2.5\ Impact + Secondary\ PM2.5\ Impact = \left(0.02\ \frac{\mu g}{m3} +\ 0.0006\ \frac{\mu g}{m3}\right) = 0.02\ \frac{\mu g}{m3}$$

6.9.2 Secondary Ozone Formation Analysis

The NO_x (269.0 tons per year) emissions from the Project are greater than the lowest MERP values for 8-hour ozone from NO_x for the Upper Midwest climate zone shown in Table 4-1 of the Guidance. The VOC (250.0 tons per year) emissions from the Project are less than the lowest MERP value for the 8-hour ozone from VOC for the Upper Midwest climate zone shown in Table 4-1 of the Guidance. Therefore, air quality impacts from the Project would be expected to be greater than the critical air quality threshold (CAQT).

The NO_x and VOC precursor contributions to the 8-hour daily maximum ozone need to be considered together to determine if the Project's air quality impact would exceed the CAQT. The additive secondary impacts on 8-hour daily maximum ozone is calculated as follows:

$$\left(\frac{269.0\ tpy\ NOx}{\begin{array}{c}125\ tpy\ NOx\ 8hr\ daily\ \max\\ O_3\ MERP\end{array}}\right) + \left(\frac{250.0\ tpy\ VOC}{\begin{array}{c}1{,}560\ tpy\ VOC\ 8hr\ daily\ \max\\ O_3\ MERP\end{array}}\right) = 2.15 + 0.16 = 2.31 * 100 = 231\%$$

A value greater than 100 percent indicates that the CAQT will be exceeded when considering the combined impacts of these precursors on 8-hour daily maximum ozone; therefore, comparable hypothetical sources were identified to determine the additive secondary impacts on 8-hour daily maximum ozone.

The Project is not located in an area with complex terrain and is not located close to large sources of pollutants that would impact atmospheric chemistry or meteorology (predominately rural area). Nearby hypothetical sources located in the Upper Midwest region were identified. According to the distance analysis, the closest hypothetical source is located in St. Louis County (137.8 kilometers away). The terrain surrounding the St. Louis County source is somewhat representative of the Project site and the source is located in a rural area similar to the Project location. A review of the data indicates that the St. Louis County source is representative of this Project.

Table 6-16 lists the EPA MERPS View Qlik values for the St. Louis County source for the respective emission rates and stack height combination. These values were used to calculate the additive secondary impacts for ozone.

Table 6-16: Hypothetical Source St. Louis County Values

Metric	Emissions (tons per year)	Stack Height (meters)	MERP (tons per year)
Daily ozone NO_x	500	90	437.0
Daily ozone VOC	500	10[a]	6,036.0

Source: EPA MERPS View Qlik (Accessed November 2021)
(a) No 90 meter stack data was available; therefore, 10 meter stack data was selected.

The NO_x and VOC precursor contributions to the 8-hour daily maximum ozone were considered together to determine if the Project's air quality impact would exceed the CAQT.

$$NOx\ Impact = \left(1\ ppb * \frac{269.0\ tpy}{437.0\ tpy}\right) = 0.62\ ppb$$

$$VOC\ Impact = \left(1\ ppb * \frac{250.0\ tpy}{6{,}036.0\ tpy}\right) = 0.041\ ppb$$

The additive secondary impacts on 8-hour daily maximum ozone is calculated as follows:

$$0.61\ ppb + 0.042\ ppb = 0.66\ ppb$$

A value less than the ozone significant impact level value of 1 parts per billion (ppb) indicates that the CAQT will not be exceeded when considering the combined impacts of these precursors on 8-hour daily maximum ozone.

6.10 Dispersion Modeling Conclusion

The modeling results shown in Table 6-9 demonstrate that exceedances of NO_x, CO, PM_{10}, and $PM_{2.5}$. modeling significance levels occurred and refined modeling is required. A refined modeling analysis was conducted to demonstrate compliance with the PSD Class II Increment and NAAQS for NO_x, CO, PM_{10}, and $PM_{2.5}$. The Project will not cause or contribute to any modeled Class II PSD Increment or NAAQS exceedances.

Based on the Class I analysis, it was determined that the impacts from the Project will not significantly impact the four Class I areas and one non-Federal Class I area that are within 300 kilometers of the Project and does not require further analysis.

The operation of the Project will not cause or contribute to a significant degradation of ambient air quality. After examining the results of the model, it has been determined that the modeling requirements for PM_{10}, $PM_{2.5}$, CO, and NO_2 have been fulfilled, and no further modeling is required.

7.0 ADDITIONAL IMPACTS ANALYSIS

Section 7 overview: The references to the most current additional impacts sections are presented in Table 7-1. The model values presented in this section have been updated to reflect the latest modeling analysis.

Table 7-1: Additional Impacts Section References

Report Heading	Previous Application Reference	December 2021 Submittal Location
Construction Impacts	Section 7.1 January 2021 Submittal	Section 7.1
Vegetation Impacts	Section 7.2 January 2021 Submittal	Section 7.2
Carbon Monoxide	Section 7.2.1 December 2018 Submittal	Section 7.2.1
Carbon Dioxide	Section 7.2.1 January 2021 Submittal	Section 7.2.2
Nitrogen Oxides	Section 7.2.3 December 2018 Submittal	Section 7.2.3
Particulate Matter	Section 7.2.3 January 2021 Submittal	Section 7.2.4
Synergistic Effects of Pollutants	Section 7.2.5 December 2018 Submittal	Section 7.2.5
Sulfuric Acid Mist	Section 7.2.6 December 2018 Submittal	Section 7.2.6
Volatile Organic Compounds	Section 7.2.2 January 2021 Submittal	Section 7.2.7
Soil Impacts	Section 7.3 January 2021 Submittal	Section 7.3
Industrial, Residential, and Commercial Growth Impacts	Section 7.4 January 2021 Submittal	Section 7.4
Visibility and Deposition Analysis	Section 7.5 January 2021 Submittal	Section 7.5
Class I Area Analysis	Section 7.5.1 January 2021 Submittal	Section 7.5.1
Class II Area Analysis	Section 7.5.2 January 2021 Submittal	Section 7.5.2
Conclusion	Section 7.6 January 2021 Submittal	Section 7.6

The additional impacts analysis requirement under PSD includes the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis for the Project.

7.1 Construction Impacts

Construction for the Project has the potential for short-term adverse effects on air quality in the immediate area around the site and will not affect the attainment status for Douglas County. Diesel fumes from construction vehicles and dust from site preparation and construction vehicle operation can affect local air quality during certain meteorological conditions. However, these instances are limited in time and area of effect.

Low sulfur fuel will be used for construction vehicles that use diesel fuel. Operation of these vehicles is not expected to significantly affect ambient air quality. During prolonged periods without rainfall, fugitive construction-related dust may need to be minimized through the application of water to onsite roads used by construction equipment.

7.2 Vegetation Impacts

The following sections briefly describe the potential effects of CO, CO_2, NO_2, PM/PM_{10}/$PM_{2.5}$, H_2SO_4 mist, VOC, and synergistic effects of pollutants produced by the installation of the Project on the nearby vegetation. The potential effects of the air emissions on vegetation within the immediate vicinity of the Project were compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning (Hallgren, 1984; Hill and Littlefield, 1969; Mansfield and Freer-Smith,1984).

7.2.1 Carbon Monoxide

CO is not known to injure plants nor has it been shown to be taken up by plants. Consequently, no adverse impacts to vegetation at or near the Project are expected from CO stack emissions from the Project.

7.2.2 Carbon Dioxide

CO_2 is not known to injure plants. Long-term exposure to elevated CO_2 levels has shown to improve the efficiency of nutrient, water, and photosynthesis in some plants (Drake, et al., 1997; Leakey et al., 2009). However, the improved efficiencies that result from elevated CO_2 levels may not necessarily result in greater yields for crop plants (Morgan et al., 2005). No adverse impacts to vegetation at or near the Project are expected from CO_2 emissions from the Project.

7.2.3 Nitrogen Oxides

During fuel combustion, atmospheric and fuel-bound nitrogen is oxidized to nitrogen oxide and small amounts of NO_2 (Chang, 1981). The NO is photochemically oxidized to NO_2, which is then subsequently consumed during the production of ozone and peroxyacetyl nitrates. NO_2 has been shown to deleteriously impact vegetation (Taylor et al., 1975; Heath, 1980; Kozlowski and Constantinidou, 1986; Darrall, 1989). Typical leaf injury responses include interveinal necrotic blotches similar to SO_2 injury for angiosperms and red-brown distal necrosis in gymnosperms (Kozlowski and Constantinidou, 1986). Injury threshold concentrations vary by species and dose but are much higher than that of SO_2 as described above. In general, short-term, high concentrations of NO_2 are required for deleterious impacts on plants (Prinz and Brandt, 1985). The injury threshold concentration for typical plants that are grown in Wisconsin is 7,380 $\mu g/m^3$ for tomato (*Lycopersicon esculentum*) and annual sunflower (*Helianthus annuus*). A common, weedy plant found in Wisconsin is lamb's quarters (*Chenopodium album*); this species was not injured following 2 hours of exposure at concentrations of 1.9 $\mu g/m^3$ NO_2. Furthermore, short-term fumigations of approximately 1-hour, 20-hours, and 48-hours at NO_2 concentrations of 940 to 38,000 $\mu g/m^3$, 470 $\mu g/m^3$, and 3,000 to 5,000 $\mu g/m^3$, respectively, have been shown to deter photosynthesis in a number of herbaceous [tomato, oats (*Avena sativa*), alfalfa (*Medicago sativa*)] and woody plants (Hill and Bennett, 1970; Capron and Mansfield, 1976; Smith, 1981). Moreover, Taylor and McLean (1970), in their review of NO_2 effects on vegetation, noted that long-term exposures of phytotoxic doses of NO_2 ranged from 280 to 560 $\mu g/m^3$.

The maximum annual modeled value for the Project is 2.9 $\mu g/m^3$ and the maximum 1-hour NO_2 modeled value for the Project is 162.5 $\mu g/m^3$. These levels are low, so it is highly unlikely that NO_2 emissions will impact vegetation adjacent to or surrounding the Project.

7.2.4 Particulate Matter

Particulates have been shown to be detrimental to vegetation typically within the immediate vicinity of the source. The most obvious effect of particle deposition on vegetation is a physical smothering of the leaf surface. This will reduce light transmission to the plant and cause a decrease in photosynthesis. The maximum PM_{10} 24-hour modeled value from this Project is 25.8 $\mu g/m^3$ and the maximum $PM_{2.5}$ 24-hour modeled value is 6.3 $\mu g/m^3$. These levels are low, so it is highly unlikely that PM_{10} and $PM_{2.5}$ emissions will impact vegetation adjacent to the Project.

7.2.5 Synergistic Effects of Pollutants

Air pollutants are known to act in concert to cause injury to or decrease the plant function (Reinert et al., 1975; Omrod, 1982). Synergistic refers to the combined effects of pollutants when they are greater than is expected from the additive effect of the compounds. The inhibitory effects of SO_2 and NO_2, NO_2 and NO, NO_2 and ozone, and ozone and SO_2 have been reported in various short-term studies for crop plants (e.g., soybean, broad bean (*Vicia faba*), annual sunflower, and tomato) and various tree species that grow in

Wisconsin [e.g., eastern cottonwood (*Populus deltoides*), sugar maple (*Acer saccharum*), white ash (*Fraxinus americana*), and black oak (*Quercus velutina*)] (White et al., 1974; Wright et al., 1986; Capron and Mansfield, 1976; Furakawa et al., 1984; Okana et al., 1985; Costonis, 1970, Carlson, 1979; Jensen, 1981; Omrod et al., 1981). Concentrations of pollutants (80 to 981 $\mu g/m^3$) in these studies are higher than the concentrations predicted to occur near the Project. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the Project.

7.2.6 Sulfuric Acid Mist

H_2SO_4 mist impacts vegetation in much the same way as acid rain, causing foliar damage and necrosis. In a study that examined the effects of acidic mist on crops and trees in London, the H_2SO_4 mist concentrations in polluted regions were insufficient to produce acute injury to vegetation except in close vicinity of intense emission sources. Generally, in experimental studies, the concentrations of acidic aerosol required to produce measurable reductions in growth and noticeable injury to plants vary between 10 to 100 milligrams per cubic meter (mg/m^3). Short time exposures of 4-16 hours at rates of 100-200 mg/m^3 have been shown to cause injury to plants (Lange, 1979). Kohno and Kobayashi analyzed the effect of simulated acid rain on soybean growth in Japan and found that visible injury to the young, trifoliate leaves occurred only when the pH was below 3.0 (Kohno and Kobayashi, 1989). In the area around the Project, the average sulfate concentration in acid rain is projected to be approximately 1.5 mg/L with a pH ranging from 5.5 to 5.7 (National Atmospheric Deposition Program (NRSP-3), 2018a and 2018b). These concentrations and levels of acidity are not likely to cause foliar damage, as described in the Kohno and Kobayashi study, because the pH is not low enough.

7.2.7 Volatile Organic Compounds

VOCs are formed from the products of incomplete combustion of natural gas. Currently VOCs are not one of the six "criteria" pollutants for which the EPA has set NAAQS (EPA, 2020). Ozone is a gas created by a chemical reaction between NO_x and VOCs in the presence of sunlight. Vegetation that is impacted by ozone is commonly referred to as "ground-level" ozone, where it forms in potential harmful concentrations and becomes a primary constituent of smog. Similar to particulate matter and lead, the primary impact of smog produced by ozone on vegetation is a physical smothering of the leaf surface. Ozone also gets inside the leaf and damages the parts of the leaf that make the sugars. Ozone's effects on plants typically result in mottled markings, yellowing leaves, or a bronzed appearance. As a result, this damage to the leaves interferes with the ability of sensitive plants to produce and store food, making them more susceptible to diseases, insects, other pollutants, and harsh weather. Chronic exposures to ozone concentrations of greater than or equal to 196 $\mu g/m^3$ can cause negative impacts to vegetation (Heath, 1975). Reductions in growth and photosynthesis of trees can occur at ozone levels of less than 200 $\mu g/m^3$

(Pye, 1988). Trees typically found within the vicinity of the facility that could be impacted by such levels of ozone include sugar, silver, and red maple (*Acer saccharum, A. saccharinum* and *A. rubrum*, respectively); white ash, green ash (*Fraxinus pennsylvanica*), and black locust (*Robinia pseudoacacia*). Soybeans, corn, wheat, annual sunflower, and white clover showed decreases in photosynthetic rates with short-term (200 $\mu g/m^3$ to 1,399 $\mu g/m^3$ for 1 to 4 hours) and long-term (70 to 270 $\mu g/m^3$ for 147 to 180 hours in 3 weeks) exposures to ozone (Hill and Littlefield, 1969; Bennett and Hill, 1973, Furukawa et al., 1984; Reich and Amundson, 1985). In a study of three varieties of rice produced commercially in California that were fumigated with ozone at 0.05, 0.10, 0.15, and 0.20 ppm concentrations for 25 hours per week, the effects of the ozone exposure resulted in a reduction of growth and yield and an increase of seed sterility as the ozone concentrations increased (Thompson et al., 1983). However, the ozone exposure concentrations experienced by the three cultivars of rice are higher than would be expected to result from the Project.

It is difficult to determine the contribution the Project would have on local or regional ambient ozone levels. Photoreactive modeling runs would be required to estimate the ozone impacts resulting from the emissions of NO_x and VOC. Due to the transport effects of ozone, it is unlikely that concentrations in the vicinity of the Project would exceed NAAQS.

7.3 Soil Impacts

Eight soil types were mapped at, or in the immediate vicinity of, the Project site and include (Natural Resources Conservation Service, 2018):

- Arnheim mucky silt loam, 0 to 1 percent slopes, frequently flooded (5A)
- Moquah fine sandy loam, 0 to 3 percent slopes, frequently flooded (6A)
- Udorthents, ravines and escarpments, 25 to 60 percent slopes (92F)
- Amnicon-Cuttre complex, 0 to 4 percent slopes (262B)
- Miskoaki clay loam, 6 to 12 percent slopes (274C)
- Miskoaki clay loam, 12 to 25 percent slopes (274D)
- Bergland-Cuttre complex, 0 to 3 percent slopes (347A)
- Lupton, Cathro, and Tawas soils, 0 to 1 percent slopes (405A)

Sulfates and nitrates caused by NO_2 deposition on soil can be both beneficial and detrimental to soils depending on their composition. However, given the low expected deposition from the Project, operation of the Project should not significantly affect the soils onsite or in the immediate vicinity.

7.4 Industrial, Residential, and Commercial Growth Impacts

The Project is expected to increase employment in the area. The building phase will last approximately one year. Construction employment is expected to peak at approximately 150 skilled construction jobs. Projected employment, reflecting full-time jobs directly tied to the operation of the Project, is estimated to be five people at the facility. This will result in moderate amounts of secondary employment being created by the economic activity of the facility. In the immediate vicinity of the Project, increased vehicular traffic is expected; however, these activities are not expected to significantly impact air quality.

An increase in the construction work may temporarily increase the number of people residing in the area for the construction phase. After construction is completed, many of the new employees are expected to already live in the area surrounding the Project. However, some new employees are expected to move into the area, with only a slight increase in the residential growth in the area. This small increase in new residences is not expected to have an impact on the air quality in the area.

Adding additional electricity to the grid in this area may increase industrial growth; however, it is unknown at this time how increasing available electrical power in this area may affect future industrial growth.

7.5 Visibility and Deposition Analysis

The visibility impairment analysis is part of the additional impacts analysis requirement under PSD.

7.5.1 Class I Area Analysis

Under the PSD program, Class I areas are protected more stringently than under the NAAQS. Class I areas include national parks, wilderness areas, and other areas of special national and cultural significance.

There are four Class I areas that are within 300 kilometers of the Nemadji River Site

- Rainbow Lake Wilderness, Wisconsin (60 kilometers)
- Boundary Waters Canoe Area Wilderness, Minnesota (126 kilometers)
- Voyageurs National Park, Minnesota (182 kilometers)
- Isle Royale National Park, Michigan (237 kilometers)

There is also one non-Federal Class I area that is within 300 kilometers of the Project, Forest County Potawatomi Community Reservation, Wisconsin (261 kilometers).

Areas that have submitted requests to change the air quality status from Class II to Class I but whose request has yet to be granted were not evaluated for this Project.

Following the most recent Federal Land Managers' Air Quality Related Values Work Group (FLAG) Workshop procedures (USFS, NPS, and USFWS, 2010), the Screening Procedure (Q/D) was used to determine if the Project could opt (screen) out of an Air Quality Related Value (AQRV) assessment for visibility and deposition. Following the screening procedures in FLAG, to calculate "Q," the emissions of NO_x, SO_2, PM_{10}, and H_2SO_4 were summed based on maximum 24-hour emission rates for the two worst-case emission scenarios and then divided by the distance to the respective Class I area.

Although overall turbine operations are limited to 500 hours per year fuel oil usage, per guidance from the FLMs, the maximum 24-hour emission rate must be used and ratioed for 365-day operation to determine the "Q" value when assessing the need for a full AQRV analysis. Maximum 24-hour emissions include start-up emissions as well as 100 percent load and duct burning for both the natural gas operation and fuel oil operation. Note that the "Q" value also includes the emissions from the auxiliary equipment. Refer to Appendix C for the overall calculation breakdown and maximum emission rates for the units.

The screening analysis is summarized below for each of the areas located within 300 kilometers of the proposed Project in Table 7-2.

Table 7-2: Class I Screening Analysis

Class I Area	D (Kilometers)	Q/D	
		Fuel Oil Duct Firing[a]	Natural Gas Duct Firing[b]
Rainbow Lake Wilderness	60	9.9	7.3
Boundary Waters Canoe Area Wilderness	126	4.7	3.5
Voyageurs National Park	182	3.3	2.4
Isle Royale National Park	237	2.5	1.9
Forest County Potawatomi Community Reservation	261	2.3	1.7

(a) Q duct firing fuel oil =sum (NO_x+PM_{10}+SO_2+H_2SO_4) = 595.8 tons per year and includes start-up emissions
(b) Q duct firing natural gas =sum (NO_x+PM_{10}+SO_2+H_2SO_4) = 439.6 tons per year and includes start-up emissions

In accordance with the FLAG Guidance, if Q/D is less than 10, then no AQRV analysis is required. Based on the ratio of Q/D, all of the areas listed in the table above do not require further analysis of AQRV. Thus, no visibility or deposition analysis is anticipated for impacts to AQRVs. A notification letter will be submitted to the Federal Land Managers (FLMs) for concurrence with the above assessment.

7.5.2 Class II Area Analysis

The Project is located in a Class II area. With respect to visibility conditions around the facility, no known Class II screening visibility criteria have been recommended at this time. Per discussions with WDNR, no Class II visibility analysis is required since the application includes a complete, complex dispersion analysis.

7.6 Conclusion

Based upon the results presented in this section of the application and additional supplemental information, it was concluded that the Project will not have a significant adverse impact on the air quality, soils, vegetation, visibility, and growth in the surrounding area.

8.0 REFERENCES

Section 8.0 overview: The report reference sections are listed in Table 8-1. The previous application submittal citations are current except for the updated modeling guidance documents, which have been updated in this section. .

Table 8-1: References

Application	Report Section
December 2018 Submittal	8.0 References
June 2020 Submittal	3.0 References
January 2021 Submittal	8.0 References

AP-42 Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I Chapter 13: Miscellaneous Sources, Section 13.2.1 Paved Roads. January 2011.

Bennett, J.H. and A.C. Hill. *Absorption of Gaseous Air Pollutants by a Standardized Plant Canopy*. JAPCA 23. (1973): 203-206.

Blackman, J., M. Averyt, and Z. Taylor. *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*. Retrieved January 24, 2019 from https://www.epa.gov/sites/production/files/2016-02/documents/leakrates_circuitbreakers.pdf

Capron, A.C. and Mansfield, TA. *Inhibition of Net Photosynthesis in Tomato in Air Polluted with NO and NO_2*. Journal of Experimental Botany. *27* (1976) 1181-1186.

Carlson, RW. *Reduction in the Photosynthetic Rate of Acer, Quercus, and Fraxinus Species Caused by Sulphur and Ozone*. Environmental Pollution. 18 (1979): 159-170.

Chang, R. *Chemistry*. New York: Random House Inc., 1981.

Costonis, A.C. *Acute Foliar Injury of Easter White Pine Induced by Sulfur Dioxide and Ozone*. Phytopathology. 60 (1970): 994-999.

Darrall, N.M. *The Effect of Air Pollutants on Physiological Processes in Plants.* Plant, Cell and Environment. 12 (1989): 1-30.

Drake, B. G., Gonzales-Meler, M., and Long, S. P. *More efficient plants: a consequence of rising atmospheric CO_2?* Annual Review of Plant Physiology and Plant Molecular Biology. 48 (1997): 609-639.

Environmental Resources Management. *Project ASCENT Best Available Control Technology (BACT) Analysis*. May 2014 http://www.dep.wv.gov/daq/permitting/Documents/Appendix_E_ASCENT_BACT_Final_May2014.pdf._Accessed October 1, 2018.

Furukawa, A., M. Yokoyama, T. Ushijima, and T. Totsuka. *The Effects of NO_2 and/or NO on Photosynthesis of Sunflower Leaves.* Studies on the Effects of Air Pollutant Mixtures on Plants, Part 1. Research Report from the Institute of Environmental Studies. 65 (1984): 89-98.

Hallgren, J-E. *Photosynthetic Gas Exchange in Leaves Affected by Air Pollutants*. In M.J. Koziol and F.R. Whatley (Eds.), Gaseous Air Pollutants and Plant Metabolism (pp. 147-160). London: Buttersworth (1984).

Hart, R, P.G. Webb, R.H. Biggs, and K.M. Portier. *The Use of Lichen Fumigation Studies to Evaluate the Effects of New Emission sources on Class I Areas*. Journal of Air Pollution Association. 38 (1988): 144-147.

Heath, R.L. *Ozone. Responses of Plants to Air Pollution*. Ed. JB Mudd and TT Kozlowski. New York: Academic Press, 1975.

Heath, R.L. *Initial Events in Injury to Plants by Air Pollutants*. Annual Review of Plant Physiology. 31 (1980): 395-431.

Hill, A.C. and J.H. Bennett. *Inhibition of Apparent Photosynthesis by Nitrogen Oxides*. Atmospheric Environment. 4 (1970): 341-348.

Hill, A.C. and N. Littlefield. Ozone*: Effect on Apparent Photosynthesis, Rate of Transpiration and Stomatal Closure in Plants*. Environmental Science and Technology. 3 (1969):52-56.

Holopainen, T.H. *Types and Distribution of ultrastructural symptoms in epiphytic lichens in several urban and industrial environments in Finland*. Annales Botanica Fennici. 21 (1984): 213-229.

Huang, T.S.R., C.L. Mulchi, and M.K. Aycock, Jr. *Correlations Between Air Pollution Injury and Certain Agronomic, Chemical, and Physical Characteristics of Maryland Tobacco*. Journal Environmental Quality. 5 (1976): 352-356.

Jensen, K.F. *Growth Analysis of Hybrid Poplar Cuttings Fumigated with Ozone and Sulphur Dioxide.* Environmental Pollution (Series A). 26 (1981): 243-250.

Kohno, Y. and Kobayashi, T. *Effects of Simulated Acid Rain on the Yield of Soybean. Water, Air, and Soil Pollution*. 45 (1989), 173-181.

Kozlowski, T.T. and H.A. Constantinidou. *Responses of Woody Plants to Environmental Pollution*, Part I Sources and Types of Pollutants and Plant Responses. Forestry Abstracts. 47 (1986): 5-51.

Lange, D.S. *Effects of Sulfuric Acid Aerosols on Vegetation.* U.S. Environmental Protection Agency, Office of Research and Development, Health Effects Research Laboratory (EPA-600/3-79-002). Triangle Park, NC. (1979).

Leakey A.D.B., E.A. Ainsworth, C.J. Bernacchi, A. Rogers, S.P. Long, D.R. Ort. *Elevated CO_2 effects on plant carbon, nitrogen, and water relations: six important lessons from FACE*. Journal of Experimental Botany. 60 (2009): 2859-2876.

LeBlanc, F. and D.N. Rao. *Effects of Air Pollutants on Lichens and Bryophytes*. Responses of Plants to Air Pollution. Ed. JB Mudd and TT Kozlowski. New York: Academic Press, 1975.

Linzon, S.N. *Effects of Gaseous Pollutants on Forests in Eastern North America*. Water, Air, and Soil Pollution. 31 (1986):537-550.

Mansfield, T.A. and P-H Freer-Smith. *The Role of Stomata in Resistance Mechanisms.* Gaseous Air Pollutants and Plant Metabolism. Ed. M.J. Koziol and F. R. Whatley. London: Buttersworth, (1984). 131-146

McCune, B. *Lichen Communities along O_3 and SO_2 Gradients in Indianapolis*. The Bryologist. 91 (1988): 223-228.

Morgan P.B., G.A. Bollero, R.L. Nelson, F.G. Dohleman, and S.P. Long. *Smaller than predicted increase in aboveground net primary production and yield of field grown soybean under fully open air (CO_2) elevation*. Global Change Biology. 11 (2005): 1856-186.

National Atmospheric Deposition Program (NRSP-3). 2018a. Sulfate Ion Concentration, 2016. NADP Program Office, Wisconsin State Laboratory of Hygiene, 465 Henry Mall, Madison, WI 53706. Retrieved 1 June 2018 from http://nadp.slh.wisc.edu/maplib/pdf/2016/SO4_conc_2016.pdf.

National Atmospheric Deposition Program (NRSP-3). 2018b. Hydrogen Ion Concentration as pH from Measurements Made at the Central Analytical Laboratory, 2016. NADP Program Office, Wisconsin State Laboratory of Hygiene, 465 Henry Mall, Madison, WI 53706. Retrieved June 1, 2018 from http://nadp.slh.wisc.edu/maplib/pdf/2016/pH_2016.pdf.

Natural Resources Conservation Service. 2018. Soil Survey of Douglas County, Wisconsin. Retrieved June 1, 2018 from https://sdmdataaccess.nrcs.usda.gov/.

Okana, K, O. Ito, G. Takeba, A. Shimizu, and T. Totsuka. *Effects of O_3 and NO_2 Alone or in Combination on the Distribution of 13C-Assimilate in Kidney Bean Plants*. Japanese Journal of Crop Science. 54 (1985): 152-159.

Omrod, D.P. *Air Pollutant Interactions in Mixtures. Effects of Gaseous Air Pollution in Agriculture and Horticulture*. Ed. M.H. Unsworth and D.P. Omrod. London: Butterworth, 1982.

Omrod, D.P., V.J. Black, and M.H. Unsworth. *Depression of Net Photosynthesis in Vicia faba L. Exposed to Sulphur Dioxide and Ozone*. Nature (London). 291 (1981): 585-586.

Prinz, B. and C.J. Brandt. *Effects of Air Pollution on Vegetation. Pollutants and Their Ecotoxicological Significance*. Ed. HW Nurnberg. New York: John Wiley & Sons, 1985. 67-84.

Pye, J.M. *Impact of Ozone on the Growth and Yield of Trees: A Review*. J. Environ. Qual. 17. (1988). 347-360.

Reich, P.B. and R.G. Amundson. *Ambient Levels of O_3 Reduce Net Photosynthesis in Tree and Crop Species*. Science 230 (1985): 566-670.

Reinert, R.A., A.S. Heagle, W.W. Heck. *Plant Responses to Pollutant Combinations. Responses of Plants to Air Pollution.* Ed. J.B. Mudd and T.T. Kozlowski. London: Academic Press, 1975.

Reisman and Frisbie, 2004. *Calculating Realistic PM_{10} Emissions from Cooling Towers*. AWMA, 2001 Florida Conference Proceedings. Abstract No. 216, Session No. AM-1b.

Siemens Industry, Inc., *Tech Topics – SF_6 Gas in Medium Voltage Switchgear*. May 2013. Retrieved January 25, 2019 from https://w3.usa.siemens.com/smartgrid/us/en/newsletters/archive/pages/sf6-gas-in-medium-voltage-switchgear.aspx

Smith, W. H. *Air Pollution and Forests*, New York: Springer-Verlag, 1981.

Taylor, O.C. and D.C. McLean. *Nitrogen Oxides and Peroxyacyl Nitrates. Recognition of Air Pollution Injury to Vegetation: A Pictorial Atlas*. Ed. JS Jacobsen. Pittsburgh: Air Pollution Control Association, 1970. E1-E14.

Taylor, O.C., C.R. Thompson, D.T. Tingey, and R.A. Reinert. *Oxides of Nitrogen. Responses of Plants to Air Pollution*. Ed. JB Mudd and TT Kozlowski. New York: Academic Press, 1975. 122-140

Texas Commission on Environmental Quality. *Air Permit Technical Guidance for Chemical Sources Fugitive Guidance.* APDG 6422v2, Revised June 201www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fugitive-guidance.pdf

Thompson, C.R., Kats G., Dawson, P., Wolf, J., and Bytnerowicz, A. *Effects of Ozone or SO_2 on Growth and Yield of Rice, Final Report*. California Air Resources Board. Statewide Air Pollution Research Center, University of California, Riverside, California. (1983).

Tingey, D.T., R.A. Reinert, J.A. Dunning, and W.W. Heck. *Vegetation Injury from the Interaction of Nitrogen Dioxide and Sulfur Dioxide*. Phytopathology. 61 (1971): 1506-1511.

Treshow, M and F.K. Anderson. *Plant Stress and Air Pollution*. New York: John Wiley & Sons, 1989.

U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, 4.3.5, *Electric Power System and Magnesium: Substitutes for SF_6,* November 2003, Page 185.

U.S. Environmental Protection Agency. *Ambient Air Monitoring Guidelines for Prevention of Significant Deterioration (PSD)*. EPA-450/4-87-007. North Carolina: Office of Air Quality Planning and Standards, 1987.

U.S. Environmental Protection Agency. *Control of Open Fugitive Dust Sources*. EPA-450/3-88-008. September 1988.

U.S. Environmental Protection Agency. *Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program* (Memorandum from Peter Tsirigotis). April 17, 2018a.

U.S. Environmental Protection Agency. *Guidance on the Development of Modeled Emission Rates for Precursors (MERPS) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program.* Memo from Richard A. Wayland. April 30, 2019.

U.S. Environmental Protection Agency. *Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations)*. EPA-450/4-80-023LR. North Carolina: Office of Air Quality Planning and Standards, 1985.

U.S. Environmental Protection Agency. *Haul Road Workgroup Final Report Submission to EPA-OAQPS.* Memo from Tyler Fox. March 2, 2012.

U.S. Environmental Protection Agency. *Hazardous Air Pollutant Emissions from Process Units in the Synthetic Organic Chemical Manufacturing Industry – Background Information for Proposed Standards Volume 1C: Model Emission Sources*. EPA-453/D-92-016c. North Carolina: Office of Air Quality Planning and Standards, November 1992.

U.S. Environmental Protection Agency. *New Source Review Workshop Manual – Draft.* North Carolina: Office of Air Quality Planning and Standards, 1990.

U.S. Environmental Protection Agency. *NAAQS Table*. Available online at https://www.epa.gov/criteria-air-pollutants/naaqs-table%20. Accessed December 15, 2020.

U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. EPA-453/R-95-017. North Carolina: Office of Air Quality Planning and Standards, November 1995.

U.S. Environmental Protection Agency. *PSD and Title V Permitting Guidance for Greenhouse Gases.* North Carolina: Office of Air Quality Planning and Standards, March 2011.

U.S. Environmental Protection Agency. *Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches to Address Ozone and Fine Particulate Matter*. EPA-HQ-OAR-2015-0310. Final rule, January 17, 2017. (82 FR 5182).

U.S. Environmental Protection Agency. SF_6 Emission Reduction Partnership for Electric Power Systems 2014 Annual Report. March 2015. Retrieved January 25, 2019 from https://www.epa.gov/sites/production/files/2016-02/documents/sf6_annrep_2015_v9.pdf

U.S. Environmental Protection Agency. *User's Guide for the AMS/EPA Regulatory Model –AERMOD*. EPA-454/B-21-001. North Carolina: Office of Air Quality Planning and Standards, April 2021.

U.S. Forest Service, National Park Service, and the U.S. Fish and Wildlife Service. (2010). *Federal Land Managers' Air Quality Related Values Workgroup (FLAG). Phase I Report – Revised (2010)*. Natural Resources Report NPS/NRPC/NRR-2010/232.

Westman, K.P. Preston, L.B. Weeks, and W.E. *SO_2 Effects on the Growth of Native Plants*. SO_2 and Vegetation. Ed. WE Winner et al. Palo Alto: Stanford University Press, 1985.

Wetmore, C.M. *Lichens and Air Quality in Indiana National Lakeshore*. Mycotaxon. XXXIII (1988): 25-39.

White, K.L., A.C. Hill, and J.H. Bennett. *Synergistic Inhibition of Apparent Photosynthesis Rate of Alfalfa by Combinations of Sulphur Dioxide and Nitrogen Dioxide*. Environmental Science and Technology. 8 (1974): 574-576.

Will-Wolf, S. *Effects of a "Clean" Coal-fired Generating station on Four Common Wisconsin lichen Species.* The Bryologist. 83 (1980): 296-300.

Winner, W.E. and Mooney, H.A. *Ecology of SO_2 Resistance: III. Metabolic Changes of C_3 and C_4 Atriplex Species Due to SO_2 Fumigation*. Oecologia. 44 (1980): 49-54.

Wisconsin Department of Natural Resources. Correspondence/Memorandum - *Guidance for Including $PM_{2.5}$ in Air Pollution Control Permit Applications*. February 22, 2016.

Wisconsin Department of Natural Resources. *Guidance on Air Quality Background Concentrations*. October 15, 2021.

Wisconsin Department of Natural Resources. *Wisconsin Air Dispersion Modeling Guidelines*. AM-528 2015. March 2018.

Wright, E.A., Lucas, P.W., Cottam, D.A., and Mansfield, T.A. *Physiological Responses of Plants to* SO_2*,* O_2*, and* O_3*. Implications for Drought Resistance. Direct Effects of Dry and Wet Deposition on Forest Ecosystems — In Particular Canopy Interactions.* Lokeberg, Sweden: EEC Cost Workshop, 1986.

APPENDIX A – FORMS

State of Wisconsin
Department of Natural Resources
dnr.wi.gov

Facility Details and Permit Actions
Air Pollution Control Permit Application

Form 4530-100 (R 9/17)

Notice: Use of this form is required by the Department for any air pollution control permit application filed pursuant to ss. 285.61, 285.62 or 285.66, Wis. Stats. Completion of this form is mandatory. The Department will not consider or act upon your application unless you complete and submit this application form. You are required to submit two copies in accordance with s. NR 407.05(2), Wis. Adm. Code. Personal information collected will be used for administrative purposes and may be provided to requesters to the extent required by Wisconsin's Open Records Law [ss. 19.31-19.39, Wis. Stats.].

Facility Information

1. Facility Name	2. SIC and NAICS	3. Facility ID Number (FID)
Nemadji Trail Energy Center	4911 & 221112	816127840
4. Street Address (where pollution sources are/will be located)	**5. (●) City ( ) Town ( ) Village of**	**6. County**
161 31st Street	Superior	Douglas

7. Primary Operating Activity (e.g., lead-acid battery manufacturer or sulfite paper mill)

Electric generation

8. Is the facility located in an area designated as "nonattainment"? (refer to instructions) ( ) Yes (●) No

9. If yes, indicate the pollutant(s) for the nonattainment designation

Applicant Information

10. Responsible Official Name (person legally responsible for the operation of the permitted air pollution sources [see NR 400.02(80e), Wis. Adm. Code])

Josh Skelton

11. Title	12. Email		
Vice President - Generation, South Shore Energy,LLC	jskelton@mnpower.com		
13. Mailing Address	**City**	**State**	**ZIP Code**
1259 NW 3rd St.	Cohasset	MN	55721

14. Parent Corporation or Owner Name (if not wholly owned by applicant)

South Shore Energy, LLC

15. Mailing Address	City	State	ZIP Code	Country (if not U.S.)
30 West Superior	Duluth	MN	55802	

16. Permit Contact Person – to be contacted for additional information concerning air pollution sources	17. Email
Melissa Weglarz	mweglarz@mnpower.com
18. Title	**19. Phone Number**
Environmental Audit and Policy Manager	(218) 355-3321

Permit Information

20. Construction Permit Actions:

Instructions: If applying for a construction permit action (including modification, reconstruction, relocation, replacement, and revision), you MUST also apply for an operation permit option. A check for the construction permit application fees MUST be submitted with the application forms before the department will begin their review. Application fees are listed below in section A. Additional fees may be required and a final invoice will be sent when a final permit decision is made. See ch. NR 410 for current fee amounts and additional review fees.

A. Permit Actions:
- (●) New Construction/Modification ($7,500) – Anticipated start dates: ______ Construction ______ Operation
- ( ) Construction Permit Revision ($1,500 fee)

  List Permit(s) to be revised: ______

☐ **Requesting Expedited Review** – If expedited review of construction permit is requested and fulfilled within expected time periods, the construction permit review fee—invoiced with the final permit—will include a surcharge from $4000 to $7500 depending on the type and how fast the permit is issued. See ch. NR 410 for specific expedited fees.

B. Construction Permit Exemptions (indicate one): If you are requesting a review and response to an exemption, a check must be included for the appropriate exemption fee listed below in parentheses.
- ( ) Actual Emissions-Based Exemption (for construction project only) ($1,250)
- ( ) Research & Testing ($1,250)
- ( ) Modification for source with Plant-wide Applicability Limit ($1,500 / $2,400 with modeling)
- ( ) Significant Net Emissions Increase ($5,500 / $6,500 with modeling)
- ( ) General exemption ($500 - NR 406.04(2))
- ( ) Specific exemptions ($500) – **Select appropriate code citation(s) from list:** ______
- ( ) Other: ______

For more information on exemption citations: https://docs.legis.wisconsin.gov/code/admin_code/nr/400/406.pdf

C. Operation Permit type for Construction Action **(select one)**:
- (●) Original – if you currently do not have a facility-wide operation permit
- ( ) Revision – so that your facility-wide operation permit will be revised to reflect the proposed project
- ( ) Renewal – if you are renewing your facility-wide operation permit in conjunction with the proposed project

21. Operation Permit Actions:

A. Type of Operation Permit Requested **(select one)**:

- (●) Part 70 Source
- ( ) Synthetic Minor, Non - Part 70 Source
- ( ) Non - Part 70 Source
- ( ) Elective

NOTE: Facilities that do not have a facility-wide operation permit issued MUST select the appropriate option. All other requests should indicate type of permit, to reflect continued or changing status.

B. Renewal

- ( ) Operation Permit Renewal

NOTE: For more information, see website on streamlined renewal application options.

C. Operation Permit Revision: (select one revision type – check code for criteria)

- ( ) Administrative Revision (NR 407.11)
- ( ) Minor Revision (NR 407.12)
- ( ) Significant Revision (NR 407.13)

List Permit(s) to be revised: ______________________

D. Operation Permit Exemption Options:
(select one type for entire facility)

- ( ) Actual Emissions Based Exemption (NR 407.03(1m))
- ( ) Natural Minor Source Exemption (NR 407.03(1s))

IMPORTANT: The exemption options in Section D. require revocation of existing operation and/or construction permits. Certain construction permit conditions cannot be revoked, and therefore the department would be unable to revoke the permits. Review all existing permits for case-by-case determinations, especially NR 405/NR 408, and discuss with department staff whether conditions are revocable.

E. Other Operation Permit Exemption Options:

- ( ) General exemptions – NR 407.03(2)
- ( ) Specific categories – Must be only air pollution source at entire facility

Select appropriate code citation(s) from list: ______________________

22. For All Permit Actions:

Is additional information attached? (●) Yes ( ) No

Submit two paper copies of completed form(s), with ink signature on this form, and additional information to:

WISCONSIN DEPARTMENT OF NATURAL RESOURCES
BUREAU OF AIR MANAGEMENT
P.O. BOX 7921
MADISON, WI 53707-7921

OR Email an electronic copy to DNRAMAirPermit@wisconsin.gov and mail one complete paper copy with ink signature to the address above.

23. Signature of Responsible Official

A. Statement of Completeness:

I have reviewed this application in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this application are true, accurate and complete.

B. Certification of Facility Compliance Status: (select one box only) **This is not a requirement of Non-Part 70 Sources.**

(●) I certify that the facility described in this air pollution permit application is fully in compliance with all applicable requirements.

( ) I certify that the facility described in this air pollution permit application is fully in compliance with all applicable requirements, except for the following emissions unit(s) (list all non-complying units): ______________________

[signature] 12-2-21
Signature of Responsible Official Date Signed

State of Wisconsin
Department of Natural Resources
APPLICATION

FACILITY PLOT PLAN
AIR POLLUTION CONTROL PERMIT

Form 4530-101 Rev. 12-99

Use of this form is required by the Department for any air pollution control permit application filed pursuant to ss. 285.61, 285.62 or 285.66, Wis Stats. Completion of this form is mandatory. The Department will not consider or act upon your application unless you complete and submit this form. It is not the Department's intention to use any personally identifiable information from this form for any other purpose.

In order for a comprehensive air quality analysis to be accomplished, a facility plot plan MUST be included with the permit application. If the application is for an initial operation permit, submit the elements under #2 below. If the application is for a renewal, answer #1 below first.

1. Have there been changes to the facility plot plan since the previous operation permit application was submitted?

☐ No. The plot plan submitted with the original application can be used for the renewal.
☒ Yes. An up-to-date plot plan is attached.

2. If there have been changes to the facility plot plan since the last operation permit application submittal, RESUBMIT an up-to-date plot plan which must include the following or the permit application will be deemed incomplete:

FOR DEPARTMENT USE ONLY

COMPLETE	INCOMPLETE	NOT APPLICABLE	
☐			1. A building layout (blueprint, plan view) including all buildings occupied by or located on the site of the facility.
☐			2. The maximum height of each building (excluding stack height).
☐			3. The location and numerical designation of each stack. Please ensure these designations correspond to the appropriate stacks listed on the other permit forms in this application.
☐			4. The location of fenced property lines (if any).
☐			5. Identify direction "North" on all submittals.
☐			6. All drawings shall be to scale and shall have the scale graphically depicted.
☐			7. An additional regional map depicting the facility location in relation to the surrounding vicinity (roads or other features) shall be included.

Are there any outdoor storage piles on the facility site? ☐ Yes ☒ No

If so, what material does the pile(s) consist of?

Are there any dirt roads or unpaved parking lots on the facility site? ☐ Yes ☒ No

From January 2021 Application

State of Wisconsin
Department of Natural Resources

SOURCE AND SITE DESCRIPTIONS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-102 Rev. 12-99 Information attached? _Y_ (y/n)

Use of this form is required by the Department for any air pollution control permit application filed pursuant to ss. 285.61, 285.62 or 285.66, Wis Stats. Completion of this form is mandatory. The Department will not consider or act upon your application unless you complete and submit this form. It is not the Department's intention to use any personally identifiable information from this form for any other purpose.

1. Briefly describe the proposed project or existing Unit(s) to be permitted. Attached supplemental forms as needed.

The proposed project is a combined-cycle combustion turbine electricity generation facility. Emission units will include one H-class combustion turbine with a heat recovery steam generator (HRSG) and one steam turbine generator. The combustion turbine will primarily combust pipeline-grade natural gas and will combust fuel oil as a back-up fuel. Other emission units for the project include an auxiliary boiler, two natural gas-fired gas heaters, an emergency diesel fire pump, an emergency diesel generator, fuel oil storage tanks, SF_6 circuit breakers, haul road truck traffic, and piping component fugitives.

For Renewal Applications:
1. Were any new or modified emissions units installed/modified at the facility since the last operation permit issuance date?
   - ☑ No. Proceed to form 4530-102A.
   - ☐ Yes. Answer the following questions:

2. Briefly describe any new/modified emissions units installed at the facility since the last operation permit issuance date and include the following information. Attach supplemental forms as needed.

   a. List the Department issued construction and/or operation permit number as applicable (identifying which units were covered by which permit if multiple permits issued).

      i. If operation permit application forms were submitted for the new emission unit(s) covered by the construction permit mentioned above, reference the date of that application.

      ii. For Part 70 Sources Only: If no operation permit application forms were submitted for the new emissions unit(s) covered by the construction permit mentioned above, complete the appropriate forms 4530-118 through 4530-125.

   b. Include the Department issued construction permit exemption number, if one was assigned, or reference the date of the letter of the exemption.

2. Site Description

The Project will be located east of the existing Enbridge Energy Superior Terminal Facility on the banks of the Nemadji River in the City of Superior in Douglas County, Wisconsin.

From January 2021 Application

State of Wisconsin
Department of Natural Resources

SOURCE DESCRIPTION - SUPPLEMENTAL
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-102A Rev. 12-99 Information attached? _N_ (y/n)

Use of this form is required by the Department for any air pollution control permit application filed pursuant to ss. 285.61, 285.62 or 285.66, Wis Stats. Completion of this form is mandatory. The Department will not consider or act upon your application unless you complete and submit this form. It is not the Department's intention to use any personally identifiable information from this form for any other purpose.

1. List all significant existing or proposed air pollution units, operations, and activities at the facility. A short narrative of the inventory of air pollution emissions unit (e.g., boiler, printing line, etc.) followed by equipment specifications will suffice. If the facility consists of several individual emission units, present this information in an outline format. (See instruction booklet for an example Unit description.)

A. Combustion Turbine, EU01
Combined cycle with duct burner –S01, P01, C01a (SCR), C01b (oxidation catalyst)
Manufacturer – Siemens SGT6-80000H
Fuel – Natural gas (primary), Fuel oil (back-up)
Maximum continuous heat input – 4,671 MMBtu/hr HHV when combusting natural gas, 4,027 MMBtu/hr, HHV when combusting diesel fuel oil with a natural gas-fired duct burner
Maximum hourly fuel combustion – 4.58 MMscf/hr (natural gas); 22,050 gal/hr (fuel oil)

B. Auxiliary Boiler, EU02, S02, B02, C02 (ultra-low NO_x burners), Flue Gas Recirculation, and Oxidation Catalyst)
Manufacturer – to be determined
Fuel – Natural gas
Maximum continuous heat input – 100 MMBtu/hr
Maximum hourly fuel combustion- 98,040 scf/hr

C. Circuit Breakers, EU 03, F03
Three 345-kV and two 19-kV circuit breakers
Manufacturer – to be determined

D. Natural Gas Heater #1, EU04, S04, P04
Manufacturer – to be determined
Fuel – Natural gas
Maximum continuous heat input – 10 MMBtu/hr
Maximum hourly fuel combustion – 9,804 scf/hr

E. Natural Gas Heater #2, EU05, S05, P05
Manufacturer – to be determined
Fuel – Natural gas
Maximum continuous heat input – 10 MMBtu/hr
Maximum hourly fuel combustion – 9,804 scf/hr

F. Emergency Diesel Fire Pump, EU06, S06, P06
Manufacturer – to be determined
Fuel – Fuel oil
Maximum continuous heat input – 282 HP
Maximum hourly fuel combustion – 14.1 gallons per hour

G. Emergency Diesel Generator, EU07, S07, P07
Manufacturer – to be determined
Fuel – Fuel oil
Maximum continuous heat input – 1,490 HP
Maximum hourly fuel combustion – 150 gallons per hour

H. Storage Tank(s)
T01 - One 180,000-gallon fuel oil tank (backup fuel for combustion turbine)
T02 - One 1,700-gallon diesel generator tank
T03- One 350-gallon diesel fire pump tank

I. Haul road fugitives, F01

J. Piping component fugitives, F02

For Renewal Applications:

1. If there were any new or modified emissions units installed/modified at the facility since the last operation permit issuance date:

   a. If any of these new/modified units were exempt from construction permit requirements, but are significant emissions units and operation permit application(s) for the new unit(s) were submitted to the Department reference the date of those submittals.

   b. If any of the new/modified units are insignificant emissions units list them on form 4530-102B.

   c. If any of the new/modified emissions units do not fit any of the above categories, fill out the appropriate forms for each emissions unit as follows:

      i. For Part 70 Sources: Fill out the appropriate forms 4530-103 through 4530-133; OR

      ii. For Synthetic Minor Non Part-70 Sources and Non-Part 70 Sources: Fill out the appropriate forms 4530-103 through 4530-117 and 4530-126 through 4530-129.

State of Wisconsin
Department of Natural Resources
APPLICATION

SOURCE DESCRIPTION - SUPPLEMENTAL
AIR POLLUTION CONTROL PERMIT

Form 4530-102B Rev. 12-99 Information attached? _N_ (y/n)

Use of this form is required by the Department for any air pollution control permit application filed pursuant to ss. 285.61, 285.62 or 285.66, Wis Stats. Completion of this form is mandatory. The Department will not consider or act upon your application unless you complete and submit this form. It is not the Department's intention to use any personally identifiable information from this form for any other purpose.

1. Mark all insignificant existing or proposed air pollution units, operations, and activities at the facility listed below. If not listed, provide a short narrative of the inventory of air pollution emissions unit (e.g., boiler, printing line, etc.) followed by equipment specifications. If the facility consists of several individual emission units, present this information in an outline format. **For Renewal Applications, identify those that are new since the last update to your application.** (See instruction booklet for an example Unit description.)

☒ Maintenance of Grounds, Equipment, and Buildings (lawn care, painting, etc.)

☒ Boiler, Turbine, and HVAC System Maintenance

☒ Pollution Control Equipment Maintenance

☐ Internal Combustion Engines Used for Warehousing and Material Transport

☒ Fire Control Equipment

☒ Janitorial Activities

☒ Office Activities

☒ Convenience Water Heating

☒ Convenience Space Heating (< 5 million BTU/hr Burning Gas, Liquid, or Wood)

☒ Fuel Oil Storage Tanks (< 10,000 gal.)

☐ Stockpiled Contaminated Soils

☒ Demineralization and Oxygen Scavenging of Water for Boilers

☒ Purging of Natural Gas Lines

☒ Sanitary Sewer and Plumbing Venting

☐

From December 2018 Application

State of Wisconsin
Department of Natural Resources

FACILITY HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-127 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To Be Assigned~~ 816127840

3. Complete the following emissions summary for all hazardous air emissions at this facility (as defined in ch. NR 445, Wis Adm. Code, and sec. 112, 1990 Clean Air Act Amendments):

		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS SUMMARY						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

From December 2018 Application

State of Wisconsin
Department of Natural Resources

FACILITY EMISSIONS SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-129 11-93

Information attached? Y (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name Nemadji Trail Energy Center:

2. Facility identification number: ~~To Be Assigned~~ 816127840

3. Complete the following emissions summary for the listed emissions at this facility.

Air pollutant	Actual	Maximum theoretical emissions	Potential to emit	Maximum allowable
	TPY	TPY	TPY	TPY
SEE APPENDIX C FOR EMISSIONS SUMMARY				
Particulates				
Sulfur dioxide				
Organic compounds				
Carbon monoxide				
Lead				
Nitrogen oxides				
Total reduced sulfur				
Mercury				
Asbestos				
Beryllium				
Vinyl chloride				

From January 2021 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF FACILITY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-132 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: 816127840

		5. State Only		
Ambient Air Quality	NR 404, 40 CFR 50		Will comply with rule	Units not constructed yet
State Origin PSD Review	NR 405	X	Will comply with rule	Units not constructed yet
Construction Permits	NR 406	X	Will comply with rule	Units not constructed yet
Operation Permits	NR 407, 40 CFR 70		Will comply with rule	Units not constructed yet
Air Permit, Emission, and Inspection Fees	NR 410	X	Will comply with rule	Units not constructed yet
Carbon Monoxide	NR 426	X	Will comply with rule	Units not constructed yet
Malodorous Emissions and Open Burning	NR 429	X	Will comply with rule	Units not constructed yet
NO_x and SO_2	NR 432	X	Will comply with rule	Units not constructed yet
Emission Prohibition, Exceptions, Delayed Compliance Orders, and Variance	NR 436	X	Will comply with rule	Units not constructed yet
Air Contaminant Emission Inventory Reporting Requirements	NR 438	X	Will comply with rule	Units not constructed yet
Reporting, Recordkeeping, Testing, Inspection, and Determination of Compliance Requirements	NR 439	X	Will comply with rule	Units not constructed yet
Standards of Performance for New Stationary Sources	NR 440, 40 CFR 60		Will comply with rule	Units not constructed yet
Hazardous Pollutants	NR 445	X	Will comply with rule	Units not constructed yet

8. Is this facility subject to the provisions governing prevention of accidental releases of hazardous air contaminants contained in section 112(r)(7) of the Clean Air Act? ☐ Yes ☒ No

If you answered yes, please describe how you will achieve compliance with these provisions, including the requirement to formulate a plan for preventing accidental releases (sec. 112(r)(7)(B)(ii)):

	State Only	

State of Wisconsin
Department of Natural Resources

FACILITY REQUIREMENT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-133 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center | 2. Facility identification number: 816127840

3. For facilities that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this facility in compliance with all applicable requirements.

☑ Form 4530-132 includes new requirements that apply or will apply to this facility during the term of the permit. We will meet such requirements on a timely basis.

4. For facilities not presently fully in compliance, complete the following.

☐ This facility is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:

Start date: ___________ and every six (6) months thereafter

P01 From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name:	2. Facility identification number:	3. Stack identification number:
Nemadji Trail Energy Center	~~To be assigned~~ 816127840	S01

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 EU01 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ___190__ (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular ___21.28__ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal (ACFM) (at 7.9 °F)
Natural Gas = 1,488,999 (without DB),
Fuel Oil = 1,519,142 (without DB)

Maximum (ACFM) (at 7.9 °F)
Natural Gas = 1,496,266 (with DB),
Fuel Oil = 1,535,605 (with DB)

10. Exhaust gas temperature (normal): __Natural Gas = 168, Fuel Oil = 185__ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

P01

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93

Information attached? __ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S01

4. Boiler/furnace number: EU01

4a. Unit description:

Natural gas-fired combustion turbine and heat recovery steam generator operating in combined cycle. Capable of burning No. 2 fuel oil as a backup fuel. Duct burning capability for natural gas and fuel oil combustion.

5. Indicate the boiler/furnace control technology status. ☐ Uncontrolled ☑ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 ____ 4530-111 ____ 4530-112 ____ **4530-113 C01a, C01b**
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type: Combined-Cycle Combustion Turbine

7. Maximum continuous rating:
4,671 MMBtu/hr HHV for Natural Gas;
4,027 MMBtu/hr for Fuel Oil

8. Manufacturer: Siemens

9. Model number: 8000H

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Natural Gas	Fuel Oil		
Higher heating value	1,020 Btu/scf	137,000 Btu/gal		
Maximum sulfur content (Wt.%)	0.5 gr/100 SCF (annual average)	0.0015%		
Maximum ash content (Wt.%)	Negligible	Negligible		
Excess Combustion Air (%O_2)	N/A	N/A		
Moisture content (as fired) (%)	Negligible	Negligible		
Maximum hourly consumption	3.59 MMscf/hr (CT) 0.99 MMscf/hr (DB)	22,050 gal/hr (CT)		
Actual yearly consumption	40,109 MMscf/yr	11.0 x 10^6 gal/yr		

***** For this emissions unit, identify the method of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

State of Wisconsin
Department of Natural Resources

CONTROL EQUIPMENT-CATALYTIC OR THERMAL OXIDATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-113 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

Section A

1. Facility name: Nemadji Trail Energy Center
2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01
4. Unit identification number:EU01
5. Control device number: C01a
6. Manufacturer and model number: TBD
7. Date of installation: ~~06/01/2021~~
8. Describe in detail the oxidation system. Attach a blueprint or diagram of the system. Attached? No

Selective catalytic reduction of NO_x using ammonia injection and a catalyst.

9. List the pollutants to be controlled by this equipment and the expected control efficiency for each pollutant on the table below.
☐ Documentation is attached

Pollutant	Inlet pollutant concentration gr/acf	Inlet pollutant concentration ppmv	Outlet pollutant concentration gr/acf	Outlet pollutant concentration ppmv	Efficiency (%) hood capture	Efficiency (%) pollutant destruction
NOx (Natural gas)		35		2.0 @ 15% O_2		94%
NOx (Fuel oil)		42		6.0 @ 15% O_2		85%

10: Check one: ☑ Catalytic ☐ Thermal oxidizer

11. Discuss how the spent catalyst will be handled for reuse or disposal.

TBD

12. Prepare a malfunction prevention and abatement plan (if required under s. NR 439.11) for this pollution control system. Please include the following:
 a. Identification of the individuals(s), by title, responsible for inspecting, maintaining and repairing this device.
 b. Operation variables such as temperature that will be monitored in order to detect a malfunction or breakthrough, the correct operating range of these variables, and a detailed description of monitoring or surveillance procedures that will be used to show compliance.
 c. An inspection schedule and items or conditions that will be inspected. For catalytic oxidizers, discuss the replacement and/or regeneration schedule for the bed and steps you have taken to ensure the bed's proper functioning throughout its expected lifetime.
 d. A listing of materials and spare parts that will be maintained in inventory.
 e. Is this plan available for review? _No_

Section B

The following questions must be answered by sources installing new equipment or existing Units which cannot document control efficiency of this device by other means. (Catalytic/Thermal dependent on item 10)

Catalytic oxidation	Thermal oxidation
13a. Operating temperature (°F): Max _TBD_ Min	b. Operating temperature (°F): Max ____ Min
14a. Catalyst bed volume (ft^3): TBD	b. Combustion chamber volume (ft^3):
15a. Gas volumetric flow rate at combustion conditions (ACFM): TBD	b. Maximum gas velocity through the device (ft./min):
16a. Type of fuel used: TBD	b. Type of fuel used:
17a. Maximum fuel use: TBD	b. Maximum fuel used:
18a. Type of catalyst used and volume of catalyst used (ft^3): TBD	
19a. Residence time (seconds): TBD	b. Residence time (seconds):

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? n (y/n)

State of Wisconsin
Department of Natural Resources

CONTROL EQUIPMENT-CATALYTIC OR THERMAL OXIDATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-113 11-93 Information attached? __ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

Section A

1. Facility name: Nemadji Trail Energy Center
2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01
4. Unit identification number: EU01
5. Control device number: C01b
6. Manufacturer and model number: TBD
7. Date of installation: ~~TBD~~
8. Describe in detail the oxidation system. Attach a blueprint or diagram of the system. Attached? Yes

Oxidation catalyst for the oxidation of CO.

9. List the pollutants to be controlled by this equipment and the expected control efficiency for each pollutant on the table below.
☐ Documentation is attached

Pollutant	Inlet pollutant concentration		Outlet pollutant concentration		Efficiency (%)	
	gr/acf	ppmv	gr/acf	ppmv	hood capture	pollutant destruction
CO (NG or FO with DB)				1.5 @15% O_2		50-80%
CO (NG pr FO without DB)				1.5 @15% O_2		50-80%
VOC (NG or FO without)				0.6 @15% O_2		35-40%
VOC (NG with DB)				2.7 @15% O_2		35-40%
VOC (FO with DB)				3.3 @15% O_2		35-40%

10: Check one: ☑ Catalytic Thermal oxidizer

11. Discuss how the spent catalyst will be handled for reuse or disposal:
TBD

12. Prepare a malfunction prevention and abatement plan (if required under s. NR 439.11) for this pollution control system. Please include the following:
    a. Identification of the individuals(s), by title, responsible for inspecting, maintaining and repairing this device.
    b. Operation variables such as temperature that will be monitored in order to detect a malfunction or breakthrough, the correct operating range of these variables, and a detailed description of monitoring or surveillance procedures that will be used to show compliance.
    c. An inspection schedule and items or conditions that will be inspected. For catalytic oxidizers, discuss the replacement and/or regeneration schedule for the bed and steps you have taken to ensure the bed's proper functioning throughout its expected lifetime.
    d. A listing of materials and spare parts that will be maintained in inventory.
    e. Is this plan available for review? No.

Section B

The following questions must be answered by sources installing new equipment or existing Units which cannot document control efficiency of this device by other means. (Catalytic/Thermal dependent on item 10)

Catalytic oxidation	Thermal oxidation
13a. Operating temperature (°F): Max TBD Min TBD	b. Operating temperature (°F): Max ____ Min
14a. Catalyst bed volume (ft^3): TBD	b. Combustion chamber volume (ft^3):
15a. Gas volumetric flow rate at combustion conditions (ACFM): TBD	b. Maximum gas velocity through the device (ft./min):
16a. Type of fuel used: N/A	b. Type of fuel used:
17a. Maximum fuel use: TBD	b. Maximum fuel used:
18a. Type of catalyst used and volume of catalyst used (ft^3): TBD	
19a. Residence time (seconds): TBD	b. Residence time (seconds):

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93

Information attached? n__ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☑ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s): NOx

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☐ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s):

☑ Stack Testing - Form 4530-123
Pollutant(s): NOx, SO_2, CO, VOC, PM_{10}, $PM_{2.5}$, H_2SO_4, opacity

☑ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s): SO_2

☑ Recordkeeping - Form 4530-125
Pollutant(s): NO_x, SO_2 CO, VOC, PM_{10}, $PM_{2.5}$

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: 12 months after Title V issuance
and every 12 months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: 6 months after Title V issuance
and every 6 months thereafter.

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY CONTINUOUS EMISSION MONITORING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-119 11-93

Information attached? _n_ (y/n)

An installation plan for each new (i.e., proposed) Continuous Emission Monitoring (CEM) system shall be submitted with the permit application for Department approval. Installation plans for existing CEMs are not required to be submitted with the permit application. The installation plan shall contain the following information: the name and address of the source; the source facility identification number; a general description of the process and the control equipment; the pollutant or diluent being monitored; the manufacturer, model number, and serial number of each analyzer; the operating principles of each analyzer; a schematic of the CEM system showing the sample acquisition point and the location of the monitors; and an explanation of any deviations from the siting criteria in Performance Specifications 1,2,3,4,5,6 and 7 in 40 CFR part 60, Appendix B, incorporated by reference in ch. NR 484, Wis. Adm. Code.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S01

4. Unit identification number: EU01

5. Pollutant being monitored: (If other than opacity then item 6 or 7 will be required) NOx

a. Name of manufacturer: TBD

b. Model number: TBD

c. Is this an existing system ☐ Yes ☑ No

d. Installation date: ~~06/01/2021~~

e. Type ☐ In situ ☑ Extractive ☐ Dilution ☐ Other (specify)

f. Describe how the monitor works:
TBD

g. Backup system: TBD

h. ☐ The CEM system certification is attached for Department approval. ☑ If it is not attached, please submit it within 60 days of the startup of the CEM system. ☐ The certification was submitted to the Department on _____.

i. ☐ A CEM system Quality Assurance/Quality Control Plan is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the CEM system startup. ☐ The plan was submitted to the Department on _____.

6. Diluent being monitored: TBD

a. Name of manufacturer: TBD

b. Model number: TBD

c. Is this an existing system ☐ Yes ☑ No

d. Installation date: ~~06/01/2021~~

e. Type ☐ In situ ☑ Extractive ☐ O2 ☐ CO2 ☐ Other (specify)

f. Describe how the monitor works:
TBD

g. Backup system: TBD

h. ☐ The CEM system certification is attached for Department approval. ☑ If it is not attached, please submit it within 60 days of the startup of the CEM system. ☐ The certification was submitted to the Department on _____.

i. ☐ A CEM system Quality Assurance/Quality Control Plan is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the CEM system startup. ☐ The plan was submitted to the Department on _____.

7. Flow. No flow meter. Fuel flow meter will be used to calculate stack flow.

a. Name of manufacturer:

b. Model number:

c. Is this an existing system ☐ Yes ☐ No

d. Installation date:

e. Type ☐ Differential pressure ☐ Thermal ☐ Other (specify)

f. Describe how the monitor works:

g. Backup system:

h. ☐ The CEM system certification is attached for Department approval. ☐ If it is not attached, please submit it within 60 days of the startup of the CEM system. ☐ The certification was submitted to the Department on _____.

i. ☐ A CEM system Quality Assurance/Quality Control Plan is attached for Department approval. ☐ If the plan is not attached, please submit it within 60 days of the CEM system startup. ☐ The plan was submitted to the Department on _____.

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY STACK TESTING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-123 11-93

Information attached? __n__ (y/n)

The performance of an EPA stack test method for demonstrating compliance with an emission limitation has always been acceptable. EPA test methods contain quality assurance procedures that shall be strictly adhered to by the source. The applicant shall propose an appropriate program of stack testing for compliance demonstration. The stack testing program shall correlate with the corresponding emission limitation in terms of the frequency and duration of the stack tests. The Department may approve the proposed stack testing program, or other program which the Department determines to be appropriate. The procedures outlined in chapter NR 439 for stack test plans and procedures shall apply to stack test performed for ongoing compliance demonstration.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01
5. Pollutant being monitored: NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, H_2SO_4, opacity	
6. Procedure being monitored: N/A	
7. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	8. Installation date: ~~06/01/2021~~

9. EPA or Department approved test method:

EPA Test Methods 5, 7, 8, 9, 10, 25, 201A, 202

10. Backup system
N/A

11. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly ☑ Upon initial startup

***** Any measured emission rate that exceeds an emission limitation established by the permit shall be reported as an excess emission. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY FUEL SAMPLING AND ANALYSIS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-124 11-93

Information attached? n (y/n)

An installation plan for each fuel sampling and analysis system (FSA) may be submitted with the permit application for Department approval. The installation plan shall contain the following information: the name and address of the source; the source facility identification number; a general description of the process and the control equipment; the type of fuel being sampled; the manufacturer, model number, and serial number of each sampler; and a schematic of the FSA system showing the sample acquisition point and the location of the machine that produces the daily, weekly, or monthly composite fuel sample. A completed form 4530-124, supplemented to satisfy the requirements of this paragraph, may constitute an installation plan for a FSA system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01
5. Pollutant being monitored: SO_2	6. Fuel being sampled: Natural gas and fuel oil

7. List the ASTM fuel sample collecting and analyzing methods used:

In accordance with 40 CFR Part 75

8. Is this an existing FSA system? ☐ Yes ☑ No	9. Installation date: ~~06/01/2021~~

10. ☐ Automated sampling ☑ Manual sampling

11. Backup system? No

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly ☑ Per shipment of fuel

13. Indicate by checking:

☐ The FSA system certification is attached for Department approval. ☑ If the certification is not attached, please submit it within 60 days of the FSA system startup. ☐ The certification was submitted to the Department on ____.

☐ A FSA quality assurance/quality control plan for fuel sampling program is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the CEM startup system. ☐ The plan was submitted to the Department on _____.

***** Any composite sample over the emission limit

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01
5. Pollutant(s) being monitored: PM_{10}, $PM_{2.5}$, VOC	6. Material or parameter being monitored and recorded: fuel usage

7. Method of monitoring and recording:

Fuel Flow

8. List any EPA methods used:
N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system:

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on ______.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01

5. Unit material description: Combined Cycle Turbine combusting natural gas and fuel oil

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? _yes, see Appendix C

		Units		Units		
SEE APPENDIX C FOR EMISSIONS CALCULATIONS						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? Yes, see Appendix C

		U	TPY		U	TPY				U	TPY
Particulates	SEE APPENDIX C FOR EMISSIONS CALCULATIONS							TPY			
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01

		7. State Only		
Nitrogen Dioxide	40 CFR 60.4320(a) (Subpart KKKK)		15 ppm at 15 percent O_2 for natural gas; 42 ppm at 15 percent O_2 for fuel oil.	Units not constructed yet
Sulfur Dioxide	40 CFR 60.4330 (Subpart KKKK)		0.90 lb/MW-hr gross output	Units not constructed yet
GHG (CO_2)	40 CFR Part 60, Subpart TTTT		1,000 lb/MW-hr gross output (90% NG) or petition for other standard	Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet
Nitrogen Dioxide	NR 432 – Clean Air Interstate Rule NOx Allowances,		Replaced by Cross-State Air Pollution Rule	Units not constructed yet
Ammonia - SCR	NR 445	X	N/A	Units not constructed yet
Carbon Monoxide	NR 426	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Particulate	NR 415.06(2)(c)	X	0.10 lb PM/MMBtu	Units not constructed yet
Nitrogen Dioxide	40 CFR 60.4320(a) (Subpart KKKK)		96 ppm @ 15% O2 at temperatures below 0 degress Fahrenheit	Units not constructed yet

	State Only	

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

P01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93

Information attached? n__ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S01	4. Unit identification number: EU01

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.

☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840	3. Stack identification number: S02

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 EU02 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: __110__ (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular __3.50__ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal __27,709__ (ACFM) Maximum __27,709__ (ACFM)

10. Exhaust gas temperature (normal): __290__ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Boiler/furnace number: EU02

4a. Unit description:
100-MMBtu/hr Auxiliary boiler responsible for delivering supplemental steam to the combined-cycle combustion turbine.

5. Indicate the boiler/furnace control technology status. ☐ Uncontrolled ☑ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 C02 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type: Unknown	7. Maximum continuous rating: 100 MMBtu/hr
8. Manufacturer: TBD	9. Model number: TBD

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Natural Gas			
Higher heating value	1,020 Btu/scf			
Maximum sulfur content (Wt.%)	Pipeline-grade			
Maximum ash content (Wt.%)	N/A			
Excess Combustion Air (%O_2)	N/A			
Moisture content (as fired) (%)	N/A			
Maximum hourly consumption	98,039 scf/hr			
Actual yearly consumption	859 x 10^6 scf			

***** For this emissions unit, identify the method of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CONTROL EQUIPMENT MISCELLANEOUS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-110 11-93 Information attached? n__ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02
5. Control device number: C02	

6. Manufacturer and model number: TBD

7. Date of installation: ~~06/01/2021~~

8. Describe in detail the device in use. Ultra-low NO_x burners and flue gas recirculation (FGR) and Oxidation Catalyst (OxCat)

Attach a diagram of the system. Attached? _No

9. List the pollutants to be controlled by this equipment and the expected control efficiency for each pollutant on the table below.
☐ Documentation is attached?

Pollutant	Inlet pollutant concentration		Hood capture efficiency (%)	Outlet pollutant concentration		Efficiency (%)
	gr/acf	ppmv		gr/acf	ppmv	
NO_x			50%		9 ppm	0.011 lb/MMBtu
VOC			50%			0.0027 lb/MMBtu
CO			90%			0.0037 lb/MMBtu

10. Discuss how the collected material will be handled for reuse or disposal.
Ultra-low NO_x burners control the formation of NO_x using a two-stage combustion process. Oxidation catalyst system is an add-on control that converts CO and VOC to CO2 by use of a catalyst.

11. Prepare a malfunction prevention and abatement plan (if required under s. NR 439.11) for this pollution control system. Please include the following:

a. Identification of the individuals(s), by title, responsible for inspecting, maintaining and repairing this device.
b. Operation variables such as temperature that will be monitored in order to detect a malfunction or breakthrough, the correct operating range of these variables, and a detailed description of monitoring or surveillance procedures that will be used to show compliance.
c. What type of monitoring equipment will be provided (temperature sensors, pressure sensors, CEMs).
d. An inspection schedule and items or conditions that will be inspected.
e. A listing of materials and spare parts that will be maintained in inventory.
f. Is this plan available for review? ___No

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☐ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s):

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☐ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s):

☐ Stack Testing - Form 4530-123
Pollutant(s):

☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s): 2

☑ Recordkeeping - Form 4530-125
Pollutant(s): All

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 12 months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 6 months thereafter.

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02
5. Pollutant(s) being monitored: SO_2	6. Material or parameter being monitored and recorded: Sulfur content of natural gas.

7. Method of monitoring and recording:
Owners will keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage of natural gas.

8. List any EPA methods used:
N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☒ Daily ☐ Weekly ☐ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02
5. Pollutant(s) being monitored: All	6. Material or parameter being monitored and recorded: Hours of operation of the natural gas heater will be recorded so that emissions may be calculated.

7. Method of monitoring and recording:
____Hours of operation

8. List any EPA methods used:
____Not applicable

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S02

4. Unit identification number: EU02

5. Unit material description: Natural gas combustion

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __See Appendix C

Pollutant CAS	Actual emissions		Maximum theoretical emissions		Potential to emit	
		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS CALCULATIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? See Appendix C

Air pollutant	Actual			Maximum theoretical emissions			Potential to emit		Maximum allowable		
		U	TPY		U	TPY				U	TPY
SEE APPENDIX C FOR EMISSIONS CALCULATIONS											
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02

5. Pollutant	6. Wis. Adm. Code Wis. Stats., 40 CFR	7. State Only	8. Limitation	9. Compliance Status (in or out)
Particulate	NR415	X	0.15 lb PM/MMbtu	Units not constructed yet
Sulfur Dioxide	NR 417, NSPS 40 CFR 60, Subpart Dc		Keep records of the sulfur content of the natural gas, as certified by the supplier or test data and record of the daily usage of natural gas	Units not constructed yet
Nitrogen Dioxide	NR 428	X		Units not constructed yet
Carbon Monoxide	NR 426	X		Units not constructed yet
Lead	NR 427	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet

10. Other requirements (e.g., malfunction reporting, special operating conditions from an existing permit, etc.)	State Only	Compliance Status (in or out)

** **PART 70 SOURCES ONLY:**

1. Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application. The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit **-** prior to controls **-** of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.

2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

B02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S02	4. Unit identification number: EU02

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.
☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:
Start date: ___________ and every six (6) months thereafter

State of Wisconsin

STACK IDENTIFICATION

Department of Natural Resources

AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840	3. Stack identification number: NA

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 **4530-109** ~~F01~~ F03

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ____ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal _________ (ACFM) Maximum ________ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☐ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

F03

From June 2020 Application

State of Wisconsin
Department of Natural Resources

MISCELLANEOUS PROCESSES
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-109 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: 816127840

3. Stack identification number: NA

4. Process number: ~~F01~~ F03

4a. Unit description: circuit breakers

5. Indicate the control technology status. ☑ Uncontrolled ☐ Controlled

If the process is controlled, enter the control device number(s) from the appropriate form(s):

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Source Classification Code (SCC): 31300500

7. Date of construction or last modification: ~~TBD~~

8. Normal operating schedule: __24__ hrs./day __7__ days/wk. __365__ days/yr.

9. Describe this process (please attach a flow diagram of the process).
Circuit breaker which will interrupt current flow after a fault is detected.

Attached?
~~See next page.~~
Figures are at end of Appendix A

10. List the types and amounts of raw materials used in this process:

Material	Storage/material handling process	Average usage	Units	Maximum usage	Units
SF_6	Circuit breaker (19 kV)	0.23	lbs/yr	0.23	lbs/yr
SF_6	Circuit breaker (345 kV)	10.31	lbs/yr	10.31	lbs/yr

11. List the types and amounts of finished products:

Material	Storage/material handling process	Average amount produced	Units	Maximum amount produced	Units
N/A					

12. Process fuel usage:

Type of fuel	Maximum heat input to process million BTU/hr.	Average usage	Units	Maximum usage	Units
N/A					

13. Describe any fugitive emissions associated with this process, such as outdoor storage piles, unpaved roads, open conveyors, etc.: N/A

Attached? N/A

***** For this emissions unit, identify the method(s) of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

F03

From June 2020 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93

Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☐ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s):

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☐ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s):

☐ Stack Testing - Form 4530-123
Pollutant(s):

☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s):

☑ Recordkeeping - Form 4530-125
Pollutant(s): Geenhouse gases – sulfur hexafluoride (SF_6)

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: _At date of permit issuance_
and every __12__ months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __6__ months thereafter.

F03 From June 2020 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? n (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03
5. Pollutant(s) being monitored: Greenhouse gases – sulfur hexafluoride (SF_6)	6. Material or parameter being monitored and recorded: SF_6
7. Method of monitoring and recording: recordkeeping	
8. List any EPA methods used: N/A	
9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~TBD~~
11. Backup system: N/A	
12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☒ Monthly ☐ Batch (not to exceed monthly)	

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

F03

From June 2020 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03
5. Unit material description: Greenhouse gases – SF_6	

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __no

		Units		Units		
NO HAPS EMISSIONS FROM THE CIRCUIT BREAKERS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

F03 From June 2020 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93 Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See ~~Appendix B~~ Appendix C

		U	TPY		U	TPY				U	TPY
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

SEE ~~APPENDIX B~~ Appendix C FOR EMISSION CALCULATIONS

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

F03

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? __ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03

		7. State Only		

	State Only	

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

F03

From June 2020 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: ~~F01~~ F03

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.

☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:

Start date: ___________ and every six (6) months thereafter

From June 2020 Application

State of Wisconsin
Department of Natural Resources

FACILITY REQUIREMENT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-133 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840

3. For facilities that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this facility in compliance with all applicable requirements.

☑ Form 4530-132 includes new requirements that apply or will apply to this facility during the term of the permit. We will meet such requirements on a timely basis.

4. For facilities not presently fully in compliance, complete the following.

☐ This facility is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:

Start date: ___________ and every six (6) months thereafter

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840	3. Stack identification number: S04

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 EU04 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: __15__ (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular __1.67__ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal __3,272__ (ACFM) Maximum __3,272__ (ACFM)

10. Exhaust gas temperature (normal): __750__ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Boiler/furnace number: EU04

4a. Unit description:

Natural gas-fired heater for maintaining the pipeline-grade natural gas at or above the mixture's dew point before injection in the combustion turbine.

5. Indicate the boiler/furnace control technology status. ☐ Uncontrolled ☑ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type:	7. Maximum continuous rating: 10 MMBtu/hr
8. Manufacturer: TBD	9. Model number: TBD

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Natural Gas			
Higher heating value	1,020 Btu/scf			
Maximum sulfur content (Wt.%)	Pipeline-grade			
Maximum ash content (Wt.%)	N/A			
Excess Combustion Air (%O_2)	N/A			
Moisture content (as fired) (%)	N/A			
Maximum hourly consumption	9,804 scf/hr			
Actual yearly consumption	85.9 x 10^6 scf			

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CONTROL EQUIPMENT MISCELLANEOUS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-110 11-93 Information attached? N (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S04

4. Unit identification number: EU04

5. Control device number: C04

6. Manufacturer and model number: TBD

7. Date of installation: ~~06/01/2021~~

8. Describe in detail the device in use. Attach a diagram of the system. Attached? No
Low NO_x burner – Low NO_x burners control flame temperatures by using a two-stage combustion process which limits thermal NO_x formation.

9. List the pollutants to be controlled by this equipment and the expected control efficiency for each pollutant on the table below.
☐ Documentation is attached?

Pollutant	Inlet pollutant concentration		Hood capture efficiency (%)	Outlet pollutant concentration		Efficiency
	gr/acf	ppmv		gr/acf	ppmv	
NO_x			100%			Controls emissions of NO_x to 0.049 lb/MMBtu of heat input

10. Discuss how the collected material will be handled for reuse or disposal.

N/A.

11. Prepare a malfunction prevention and abatement plan (if required under s. NR 439.11) for this pollution control system. Please include the following:

a. Identification of the individuals(s), by title, responsible for inspecting, maintaining and repairing this device.
b. Operation variables such as temperature that will be monitored in order to detect a malfunction or breakthrough, the correct operating range of these variables, and a detailed description of monitoring or surveillance procedures that will be used to show compliance.
c. What type of monitoring equipment will be provided (temperature sensors, pressure sensors, CEMs).
d. An inspection schedule and items or conditions that will be inspected.
e. A listing of materials and spare parts that will be maintained in inventory.
f. Is this plan available for review?

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? n (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

- ☐ Continuous Emission Monitoring (CEM) - Form 4530-119
  Pollutant(s):
- ☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
  Pollutant(s):
- ☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
  Pollutant(s):
- ☐ Monitoring Maintenance Procedures - Form 4530-122
  Pollutant(s):
- ☐ Stack Testing - Form 4530-123
  Pollutant(s):
- ☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
  Pollutant(s):
- ☑ Recordkeeping - Form 4530-125
  Pollutant(s): all pollutants
- ☐ Other (please describe) - Form 4530-135
  Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 12 months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 6 months thereafter.

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04
5. Pollutant(s) being monitored: SO_2	6. Material or parameter being monitored and recorded: Sulfur content of natural gas.

7. Method of monitoring and recording:
Owners will keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage of natural gas.

8. List any EPA methods used:
N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☒ Daily ☐ Weekly ☐ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04
5. Pollutant(s) being monitored: All	6. Material or parameter being monitored and recorded: Hours of operation of the natural gas heater will be recorded so that emissions may be calculated.

7. Method of monitoring and recording:
Hours of operation

8. List any EPA methods used:
Not applicable

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04
5. Unit material description: Natural Gas Combustion	

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __See Appendix C

Pollutant CAS	Actual emissions		Maximum theoretical emissions		Potential to emit	
		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS CALCULATIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? y__ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S04

4. Unit identification number: EU04

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See Appendix C

Air pollutant	Actual			Maximum theoretical emissions			Potential to emit		Maximum allowable		
		U	TPY		U	TPY				U	TPY
SEE APPENDIX C FOR EMISSIONS CALCULATIONS											
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

P04

From December 2018 Application

State of Wisconsin
Department of Natural Resources

SEE INSTRUCTIONS ON REVERSE SIDE

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04

5. Pollutant	6. Wis. Adm. Code Wis. Stats., 40 CFR	7. State Only	8. Limitation	9. Compliance Status (in or out)
Particulate	NR 415	X	0.15 lb/MMBtu	Units not constructed yet
Sulfur Dioxide	NR 417, NSPS 40 CFR 60, Subpart Dc		Keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage	Units not constructed yet
Nitrogen Dioxide	NR 428	X		Units not constructed yet
Carbon Monoxide	NR 426	X		Units not constructed yet
Lead	NR 427	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet

10. Other requirements (e.g., malfunction reporting, special operating conditions from an existing permit, etc.)	State Only	Compliance Status (in or out)

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S04	4. Unit identification number: EU04

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.

☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:
Start date: ___________ and every six (6) months thereafter

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840	3. Stack identification number: S05

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 EU05 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: 15 (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular 1.67 (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal 3,272 (ACFM) Maximum 3,272 (ACFM)

10. Exhaust gas temperature (normal): 750 (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S05

4. Boiler/furnace number: EU05

4a. Unit description:

Natural gas-fired heater for maintaining the pipeline-grade natural gas at or above the mixture's dew point before injection in the combustion turbine.

5. Indicate the boiler/furnace control technology status. ☐ Uncontrolled ☑ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type:

7. Maximum continuous rating: 10 MMBtu/hr

8. Manufacturer: TBD

9. Model number: TBD

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Natural Gas			
Higher heating value	1,020 Btu/scf			
Maximum sulfur content (Wt.%)	Pipeline-grade			
Maximum ash content (Wt.%)	N/A			
Excess Combustion Air (%O_2)	N/A			
Moisture content (as fired) (%)	N/A			
Maximum hourly consumption	9,804 scf/hr			
Actual yearly consumption	85.9 x 10^6 scf			

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CONTROL EQUIPMENT MISCELLANEOUS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-110 11-93 Information attached? N (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S05

4. Unit identification number: EU05

5. Control device number: C05

6. Manufacturer and model number: TBD

7. Date of installation: ~~06/01/2021~~

8. Describe in detail the device in use. Attach a diagram of the system. Attached? No
Low NO_x burner – Low NO_x burners control flame temperatures by using a two-stage combustion process which limits thermal NO_x formation.

9. List the pollutants to be controlled by this equipment and the expected control efficiency for each pollutant on the table below.
☐ Documentation is attached?

Pollutant	Inlet pollutant concentration		Hood capture efficiency (%)	Outlet pollutant concentration		Efficiency
	gr/acf	ppmv		gr/acf	ppmv	
NO_x			100%			Controls emissions of NO_x to 0.049 lb/MMBtu of heat input

10. Discuss how the collected material will be handled for reuse or disposal.

N/A.

11. Prepare a malfunction prevention and abatement plan (if required under s. NR 439.11) for this pollution control system. Please include the following:

a. Identification of the individuals(s), by title, responsible for inspecting, maintaining and repairing this device.
b. Operation variables such as temperature that will be monitored in order to detect a malfunction or breakthrough, the correct operating range of these variables, and a detailed description of monitoring or surveillance procedures that will be used to show compliance.
c. What type of monitoring equipment will be provided (temperature sensors, pressure sensors, CEMs).
d. An inspection schedule and items or conditions that will be inspected.
e. A listing of materials and spare parts that will be maintained in inventory.
f. Is this plan available for review?

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.
SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S05	4. Unit identification number: EU05

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

- ☐ Continuous Emission Monitoring (CEM) - Form 4530-119
  Pollutant(s):
- ☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
  Pollutant(s):
- ☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
  Pollutant(s):
- ☐ Monitoring Maintenance Procedures - Form 4530-122
  Pollutant(s):
- ☐ Stack Testing - Form 4530-123
  Pollutant(s):
- ☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
  Pollutant(s):
- ☑ Recordkeeping - Form 4530-125
  Pollutant(s): all pollutants
- ☐ Other (please describe) - Form 4530-135
  Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __12__ months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __6__ months thereafter.

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~816127840
3. Stack identification number: S05	4. Unit identification number: EU05
5. Pollutant(s) being monitored: SO_2	6. Material or parameter being monitored and recorded: Sulfur content of natural gas.

7. Method of monitoring and recording:
Owners will keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage of natural gas.

8. List any EPA methods used:
N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☒ Daily ☐ Weekly ☐ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance ***** certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application.

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. ***** Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately.

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? n (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S05	4. Unit identification number: EU05
5. Pollutant(s) being monitored: All	6. Material or parameter being monitored and recorded: Hours of operation of the natural gas heater will be recorded so that emissions may be calculated.

7. Method of monitoring and recording:
Hours of operation

8. List any EPA methods used:
Not applicable

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93 Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S05

4. Unit identification number: EU05

5. Unit material description: Natural Gas Combustion

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __See Appendix C

Pollutant CAS	Actual emissions		Maximum theoretical emissions		Potential to emit	
		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS CALCULATIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

SEE INSTRUCTIONS ON REVERSE SIDE

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S05	4. Unit identification number: EU05

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? _See Appendix C_

Air pollutant	Actual			Maximum theoretical emissions			Potential to emit		Maximum allowable		
		U	TPY		U	TPY				U	TPY
SEE APPENDIX C FOR EMISSIONS CALCULATIONS											
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S05	4. Unit identification number: EU05

5. Pollutant	6. Wis. Adm. Code Wis. Stats., 40 CFR	7. State Only	8. Limitation	9. Compliance Status (in or out)
Particulate	NR 415	X	0.15 lb/MMBtu	Units not constructed yet
Sulfur Dioxide	NR 417, NSPS 40 CFR 60, Subpart Dc		Keep records of the sulfur content of the natural gas as certified by the supplier or test data and record the daily usage	Units not constructed yet
Nitrogen Dioxide	NR 428	X		Units not constructed yet
Carbon Monoxide	NR 426	X		Units not constructed yet
Lead	NR 427	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet

10. Other requirements (e.g., malfunction reporting, special operating conditions from an existing permit, etc.)	State Only	Compliance Status (in or out)

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

P05

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S05	4. Unit identification number: EU05

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.
   - ☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.
   - ☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:
Start date: ___________ and every six (6) months thereafter

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name:	2. Facility identification number:	3. Stack identification number:
Nemadji Trail Energy Center	~~To be assigned~~ 816127840	S06

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 **EU06** 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: 15 (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular 0.5 (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal 1,813 (ACFM) Maximum 1,813 (ACFM)

10. Exhaust gas temperature (normal): 1,030 (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~816127840
3. Stack identification number: S06	4. Boiler/furnace number: EU06

4a. Unit description:

282-hp emergency diesel fire pump.

5. Indicate the boiler/furnace control technology status. ☑ Uncontrolled ☐ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type:	7. Maximum continuous rating: 1.95 MMBtu/hr
8. Manufacturer: TBD	9. Model number: TBD

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Fuel oil			
Higher heating value	137,000 Btu/gal			
Maximum sulfur content (Wt.%)	ULSD			
Maximum ash content (Wt.%)	N/A			
Excess Combustion Air (% O_2)	N/A			
Moisture content (as fired) (%)	N/A			
Maximum hourly consumption	14.1 gal/hr			
Actual yearly consumption	7,050 gal/yr			

***** For this emissions unit, identify the method of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☐ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s):

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☐ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s):

☐ Stack Testing - Form 4530-123
Pollutant(s):

☑ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s): SO_2

☑ Recordkeeping - Form 4530-125
Pollutant(s): _All_

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __12__ months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __6__ months thereafter.

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY FUEL SAMPLING AND ANALYSIS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-124 11-93

Information attached? _n_ (y/n)

An installation plan for each fuel sampling and analysis system (FSA) may be submitted with the permit application for Department approval. The installation plan shall contain the following information: the name and address of the source; the source facility identification number; a general description of the process and the control equipment; the type of fuel being sampled; the manufacturer, model number, and serial number of each sampler; and a schematic of the FSA system showing the sample acquisition point and the location of the machine that produces the daily, weekly, or monthly composite fuel sample. A completed form 4530-124, supplemented to satisfy the requirements of this paragraph, may constitute an installation plan for a FSA system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06
5. Pollutant being monitored: SO_2	6. Fuel being sampled: Diesel fuel oil

7. List the ASTM fuel sample collecting and analyzing methods used:
In accordance with 40 CFR Part 75

8. Is this an existing FSA system? ☐ Yes ☑ No	9. Installation date: ~~06/01/2021~~

10. ☐ Automated sampling ☑ Manual sampling

11. Backup system? Not applicable

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly ☑ Per shipment of diesel fuel

13. Indicate by checking:

☐ The FSA system certification is attached for Department approval. ☑ If the certification is not attached, please submit it within 60 days of the FSA system startup. ☐ The certification was submitted to the Department on ____.

☐ A FSA quality assurance/quality control plan for fuel sampling program is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the CEM startup system. ☐ The plan was submitted to the Department on _____.

***** Any composite sample over the emission limit shall be reported as an excess emission. *****

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06
5. Pollutant(s) being monitored: All	6. Material or parameter being monitored and recorded: The hours of operation of the emergency fire pump will be recorded so that emissions may be calculated.

7. Method of monitoring and recording: Hours of operation

8. List any EPA methods used:

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system:

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance ***** certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application.

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. ***** Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately.

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S06

4. Unit identification number: EU06

5. Unit material description: Fuel oil combustion

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __See Appendix C

Pollutant CAS	Actual emissions		Maximum theoretical emissions		Potential to emit	
		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS CALCULATIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? _See Appendix C_

Air pollutant	Actual			Maximum theoretical emissions			Potential to emit		Maximum allowable		
		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSIONS CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06

5. Pollutant	6. Wis. Adm. Code Wis. Stats., 40 CFR	7. State Only	8. Limitation	9. Compliance Status (in or out)
Particulate	NR415, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ		0.15 lb/MMBtu and 0.15 g/hp-hr	Units not constructed yet
Sulfur Dioxide	NR 417	X		Units not constructed yet
Nitrogen Dioxide	NR 428, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ		NMHC + NO_x = 3.0 g/hp-hr	Units not constructed yet
Carbon Monoxide	NR 426, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ		2.6 g/hp-hr	Units not constructed yet
Lead	NR 427	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet

10. Other requirements (e.g., malfunction reporting, special operating conditions from an existing permit, etc.)	State Only	Compliance Status (in or out)

P06

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93

Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S06	4. Unit identification number: EU06

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.

☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:
Start date: ___________ and every six (6) months thereafter

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name:	2. Facility identification number:	3. Stack identification number:
Nemadji Trail Energy Center	~~To be assigned~~ 816127840	S07

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 **EU07** 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☑ This stack has an actual exhaust point. ☐ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: __15__ (feet)

8. Inside dimensions at outlet (check one and complete):

☑ Circular __0.67__ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal __7,540__ (ACFM) Maximum __7,540__ (ACFM)

10. Exhaust gas temperature (normal): __890__ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☑ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☑ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

BOILER OR FURNACE OPERATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-104 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Boiler/furnace number: EU07

4a. Unit description:

1,490-hp emergency diesel generator.

5. Indicate the boiler/furnace control technology status. ☑ Uncontrolled ☐ Controlled

If the boiler/furnace is controlled, enter the control device number(s) from the appropriate forms:

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Furnace type:	7. Maximum continuous rating: 21.0 MMBtu/hr
8. Manufacturer: Cummins	9. Model number: DQFAD

10. Date of construction or last modification: ~~06/01/2021~~

11. Fuels and firing conditions:

	Primary fuel	Backup fuel #1	Backup fuel #2	Backup fuel #3
Fuel name	Fuel Oil			
Higher heating value	137,000 Btu/gal			
Maximum sulfur content (Wt.%)	ULSD			
Maximum ash content (Wt.%)	N/A			
Excess Combustion Air (%O_2)	N/A			
Moisture content (as fired) (%)	N/A			
Maximum hourly consumption	150 gal/hr			
Actual yearly consumption	75,000 gal/yr			

***** For this emissions unit, identify the method of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Unit identification number: EU07

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

- ☐ Continuous Emission Monitoring (CEM) - Form 4530-119
  Pollutant(s):
- ☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
  Pollutant(s):
- ☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
  Pollutant(s):
- ☐ Monitoring Maintenance Procedures - Form 4530-122
  Pollutant(s):
- ☐ Stack Testing - Form 4530-123
  Pollutant(s):
- ☑ Fuel Sampling and Analysis (FSA) - Form 4530-124
  Pollutant(s): SO_2
- ☑ Recordkeeping - Form 4530-125
  Pollutant(s): _All_
- ☐ Other (please describe) - Form 4530-135
  Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __12__ months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __6__ months thereafter.

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY FUEL SAMPLING AND ANALYSIS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-124 11-93

Information attached? _n_ (y/n)

An installation plan for each fuel sampling and analysis system (FSA) may be submitted with the permit application for Department approval. The installation plan shall contain the following information: the name and address of the source; the source facility identification number; a general description of the process and the control equipment; the type of fuel being sampled; the manufacturer, model number, and serial number of each sampler; and a schematic of the FSA system showing the sample acquisition point and the location of the machine that produces the daily, weekly, or monthly composite fuel sample. A completed form 4530-124, supplemented to satisfy the requirements of this paragraph, may constitute an installation plan for a FSA system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Unit identification number: EU07
5. Pollutant being monitored: SO_2	6. Fuel being sampled: Diesel fuel oil

7. List the ASTM fuel sample collecting and analyzing methods used:
In accordance with 40 CFR Part 75

8. Is this an existing FSA system? ☐ Yes ☑ No	9. Installation date: ~~06/01/2021~~

10. ☐ Automated sampling ☑ Manual sampling

11. Backup system? Not applicable

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly ☑ Per shipment of diesel fuel

13. Indicate by checking:

☐ The FSA system certification is attached for Department approval. ☑ If the certification is not attached, please submit it within 60 days of the FSA system startup. ☐ The certification was submitted to the Department on ____.

☐ A FSA quality assurance/quality control plan for fuel sampling program is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the CEM startup system. ☐ The plan was submitted to the Department on _____.

***** Any composite sample over the emission limit shall be reported as an excess emission. *****

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? _n_ (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Unit identification number: EU07
5. Pollutant(s) being monitored: All	6. Material or parameter being monitored and recorded: The hours of operation of the emergency generator will be recorded so that emissions may be calculated.

7. Method of monitoring and recording:
Hours of operation

8. List any EPA methods used:
N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~06/01/2021~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☑ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93

Information attached? y (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S07

4. Unit identification number: EU07

5. Unit material description: Fuel Oil Combustion

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? See Appendix C

Pollutant CAS	Actual emissions		Maximum theoretical emissions		Potential to emit	
		Units		Units		
SEE APPENDIX C FOR HAPS EMISSIONS CALCULATIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Unit identification number: EU07

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? _See Appendix C_

Air pollutant	Actual			Maximum theoretical emissions			Potential to emit		Maximum allowable		
		U	TPY		U	TPY				U	TPY
SEE APPENDIX C FOR EMISSION CALCULATIONS											
Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: ~~To be assigned~~ 816127840

3. Stack identification number: S07

4. Unit identification number: EU07

5. Pollutant	6. Wis. Adm. Code Wis. Stats., 40 CFR	7. State Only	8. Limitation	9. Compliance Status (in or out)
Particulate	NR415, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ		0.15 lb/MMBtu and 0.15 g/hp-hr	Units not constructed yet
Sulfur Dioxide	NR 417	X		Units not constructed yet
Nitrogen Dioxide	NR 428, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ		NMHC + NO_x = 4.8 g/hp-hr	Units not constructed yet
Carbon Monoxide	NR 426, 40 CFR Part 60, Subpart IIII, 40 CFR Part 63 ZZZZ	X	CO = 2.6 g/hp-hr	Units not constructed yet
Lead	NR 427	X		Units not constructed yet
Volatile Organic Compounds	NR 419	X		Units not constructed yet
Opacity	NR 431	X	20% opacity	Units not constructed yet

10. Other requirements (e.g., malfunction reporting, special operating conditions from an existing permit, etc.)	State Only	Compliance Status (in or out)

P07

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S07	4. Unit identification number: EU07

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.

☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.

☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.

☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:
Start date: ___________ and every six (6) months thereafter

T01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name:	2. Facility identification number:	3. Stack identification number:
Nemadji Trail Energy Center	~~To be assigned~~ 816127840	S08

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:

☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: __30__ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal ______ (ACFM) Maximum ______ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☒ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

T01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-105 11-93 Information attached? __ (y/n)

n
SEE ATTACHED SHEET FOR INSTRUCTIONS

1.Facility Name: **Nemadji River Energy Center**

2.Facility Identification Number 816127840

3.Storage Tank Number: **EU08**

4.Control Device Number (use number from appropriate Form(s) 4530-110, 111, 112, 113, 114, 115, 116, or 117)

5.Storage Tank Capacity **180,000 gallons** gallons

6.Date of Installation or Last Modification ~~06/01/2021~~

7.Tank Height: **30 ft**

8.Tank Diameter: **33 ft**

9.Color of Tank (check one)
_✓_ White __ Other__________________ __ Underground

10.Is this tank equipped with a submerged fill pipe?
_✓_ Yes __ No

11.Is this tank equipped with a pressure/vacuum conservation vent?
__ Yes _✓_ No

If yes; at what pressure is it set? ____________________(psia)
at what vacuum is it set? ____________________(psia)

12.Type of Storage Tank (check one)
__ Open Top Tank
__ Pressurized Tank
_✓_ Fixed Roof
__ External Floating Roof
__ Fixed Roof w/Internal Floating Roof
__ Variable Vapor Space
__ Other (specify) ________________________

13.For all Fixed Roof Tanks:

a.Tank Configuration (check one): _✓_ Vertical (upright cylinder) __ Horizontal

b.Tank Roof Type (check one): (required if vertical was selected)
_✓_ Cone Roof - Indicate tank roof height ____5________(feet)
__ Dome Roof - Indicate tank roof height ______________(feet) - Indicate tank shell radius ______________(feet)

14.For all Floating Roof Tanks (both internal and external) - Shell Condition (check one):
__ Light Rust __ Dense Rust __Gunite Lined

15.For External Floating Roof Tanks:

a.Tank Construction (check one): __ Welded Tank __ Riveted Tank

b.Average Wind Speed at Tank Site: __________________________(mph)

c.Rim Seal System Description (check one):
__ Shoe Mounted Primary
__ Shoe Primary, Rim Secondary
__ Shoe Primary, Shoe Secondary
__ Vapor Mounted Primary
__ Vapor Primary, Rim Secondary
__ Vapor Primary w/Weather Shield
__ Liquid Mounted Primary
__ Liquid Primary, Rim Secondary
__ Liquid Primary w/Weather Shield

d.Roof Type (check one): __ Pontoon Roof __ Double Deck Roof

e.Roof Fitting Types (indicate the number of each type):

Access Hatch (24" diameter well)
____ Bolted cover, gasketed
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed

Unslotted guide-pole well (8" diameter unslotted pole, 21" diameter well)
____ Ungasketed sliding cover
____ Gasketed sliding cover

Gauge-float well (20" diameter)
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed
____ Bolted cover, gasketed

Gauge-Hatch/sample well (8" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Vacuum Breaker (10" diameter well)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Roof Drain (3-inch diameter)
____ Open
____ 90% closed

Slotted guide-pole/sample well (8" diameter diameter slotted pole, 21" diameter well)
____ Ungasketed sliding cover, without float
____ Ungasketed sliding cover, with float
____ Gasketed sliding cover, without float
____ Gasketed sliding cover, with float

Roof leg (3" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double-deck roofs
____ Fixed

Roof leg(2-1/2" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double deck roofs
____ Fixed

Continued on following page

T01

From December 2018 Application

State of Wisconsin
Department of Natural Resources
APPLICATION

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT

Form 4530-105 11-93 Information attached?

(y/n)

page 2

16.For Internal Floating Roof Tanks:

a.Rim Seal System Description (check one): __ Vapor Mounted Primary __ Liquid Mounted Primary __ Vapor Mounted Primary plus Secondary Seal __ Liquid Mounted Primary plus Secondary Seal

b.Number of Columns: ______________________________

c.Effective Column Diameter: ____________________ (feet)

d.Deck Type (check one): __ Welded __ Bolted

e.Total Deck Seam Length: ____________________ (feet)

f.Deck Area: _____________________ (square feet)

g.Deck Fitting Types (indicate the number of each type):

Access Hatch (24" diameter)
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Automatic gauge float well
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Ladder Well (36" diameter)
____ Sliding cover, gasketed
____ Sliding cover, ungasketed

Column Well (24" diameter)
____ Builtup column-sliding cover, gasketed
____ Builtup column-sliding cover, ungasketed
____ Pipe column-flexible fabric sleeve seal
____ Pipe column-sliding cover, gasketed
____ Pipe column-sliding cover, ungasketed

Sample pipe or well (24" diameter)
____ Slotted pipe-sliding cover, gasketed
____ Slotted pipe-sliding cover, ungasketed
____ Sample well-slit fabric seal 10% open area
____ Stub drain (1" diameter)

Roof leg or hanger well
____ Adjustable
____ Fixed

Vacuum breaker (10" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

17.For Variable Vapor Space Tanks:
Volume Expansion Capacity _____________________ (gallons)

18.Complete the following table for materials to be stored in this tank:

Material Stored	Annual Throughput (gal/yr)	Daily Average Amount Stored (gallons)	Material Molecular Weight (lb/lb-mole)	Material Vapor Pressure (psia)	Storage Pressure (psia)	Average Storage Temperature (°F)	Material Liquid Density (lb/gal)
No. 2 Fuel Oil	10,791,748	180,000				Ambient	

19.Maximum Liquid Loading Rate of Tank:
_________________________ (gallons)

20.Can this tank be loaded at the same time other tanks are loaded? _____ Yes _✓_ No

If yes, indicate which other tanks can be loaded at the same time: ________________________

21.Describe the operations this tank will serve: **180,000 tank stores No. 2 fuel oil as a backup fuel for the combustion turbine at the facility.**

T01

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S08	4. Unit identification number: EU08

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See Appendix C

		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSIONS CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

T02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

SEE INSTRUCTIONS ON REVERSE SIDE

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93

Information attached? _n_ (y/n)

1. Facility name:	2. Facility identification number:	3. Stack identification number:
Nemadji Trail Energy Center	~~To be assigned~~ 816127840	S09

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:

☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ____ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal ______ (ACFM) Maximum ______ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☒ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

T02   From December 2018 Application

State of Wisconsin
Department of Natural Resources

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-105 11-93   Information attached? n__ (y/n)

SEE ATTACHED SHEET FOR INSTRUCTIONS

1.Facility Name: **Nemadji River Energy Center**   2.Facility Identification Number 816127840   3.Storage Tank Number: **EU09**

4.Control Device Number (use number from appropriate Form(s) 4530-110, 111, 112, 113, 114, 115, 116, or 117)   5.Storage Tank Capacity **1,700 gallons** gallons   6.Date of Installation or Last Modification ~~06/01/2021~~

7.Tank Height: 8.Tank Diameter: 9.Color of Tank (check one)
_✓_ White __ Other__________________ __ Underground

14 ft x 6.5 ft x 1.2 ft Belly Tank (approximate specifications)

10.Is this tank equipped with a submerged fill pipe?
_✓_ Yes __ No

11.Is this tank equipped with a pressure/vacuum conservation vent?
_✓_ Yes _✓_ No
If yes; at what pressure is it set? ____________________(psia)
at what vacuum is it set? ____________________(psia)

12.Type of Storage Tank (check one)
__ Open Top Tank   __ Fixed Roof   __ Fixed Roof w/Internal Floating Roof   _✓_ Other (specify)
__ Pressurized Tank   __ External Floating Roof   __ Variable Vapor Space   Generator Belly Tank____________

13.For all Fixed Roof Tanks:

a.Tank Configuration (check one): __ Vertical (upright cylinder)   _✓_ Horizontal

b.Tank Roof Type (check one):   __ Cone Roof - Indicate tank roof height ____________(feet)
(required if vertical was selected)   __ Dome Roof - Indicate tank roof height ____________(feet) - Indicate tank shell radius ____________(feet)

14.For all Floating Roof Tanks (both internal and external) - Shell Condition (check one):
__ Light Rust   __ Dense Rust   __Gunite Lined

15.For External Floating Roof Tanks:
a.Tank Construction (check one):   __ Welded Tank   __ Riveted Tank

b.Average Wind Speed at Tank Site: ______________________(mph)

c.Rim Seal System Description (check one):
__ Shoe Mounted Primary   __ Vapor Mounted Primary   __ Liquid Mounted Primary
__ Shoe Primary, Rim Secondary   __ Vapor Primary, Rim Secondary   __ Liquid Primary, Rim Secondary
__ Shoe Primary, Shoe Secondary   __ Vapor Primary w/Weather Shield   __ Liquid Primary w/Weather Shield

d.Roof Type (check one):   __ Pontoon Roof   __ Double Deck Roof

e.Roof Fitting Types (indicate the number of each type):

Access Hatch (24" diameter well)
____ Bolted cover, gasketed
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed

Unslotted guide-pole well
(8" diameter unslotted pole, 21" diameter well)
____ Ungasketed sliding cover
____ Gasketed sliding cover

Gauge-float well (20" diameter)
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed
____ Bolted cover, gasketed

Gauge-Hatch/sample well (8" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Vacuum Breaker (10" diameter well)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Roof Drain (3-inch diameter)
____ Open
____ 90% closed

Slotted guide-pole/sample well (8" diameter diameter slotted pole, 21" diameter well)
____ Ungasketed sliding cover, without float
____ Ungasketed sliding cover, with float
____ Gasketed sliding cover, without float
____ Gasketed sliding cover, with float

Roof leg (3" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double-deck roofs
____ Fixed

Roof leg(2-1/2" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double deck roofs
____ Fixed

Continued on following page

T02

From December 2018 Application

State of Wisconsin
Department of Natural Resources
APPLICATION

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT

Form 4530-105 11-93 Information attached?

(y/n)

16.For Internal Floating Roof Tanks:

a.Rim Seal System Description (check one): __ Vapor Mounted Primary __ Vapor Mounted Primary plus Secondary Seal
__ Liquid Mounted Primary __ Liquid Mounted Primary plus Secondary Seal

b.Number of Columns: ________________________________

c.Effective Column Diameter: ______________________ (feet)

d.Deck Type (check one): __ Welded __ Bolted

e.Total Deck Seam Length: ______________________ (feet)

f.Deck Area: _______________________ (square feet)

g.Deck Fitting Types (indicate the number of each type):

Access Hatch (24" diameter)
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Automatic gauge float well
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Ladder Well (36" diameter)
____ Sliding cover, gasketed
____ Sliding cover, ungasketed

Column Well (24" diameter)
____ Builtup column-sliding cover, gasketed
____ Builtup column-sliding cover, ungasketed
____ Pipe column-flexible fabric sleeve seal
____ Pipe column-sliding cover, gasketed
____ Pipe column-sliding cover, ungasketed

Sample pipe or well (24" diameter)
____ Slotted pipe-sliding cover, gasketed
____ Slotted pipe-sliding cover, ungasketed
____ Sample well-slit fabric seal 10% open area
____ Stub drain (1" diameter)

Roof leg or hanger well
____ Adjustable
____ Fixed

Vacuum breaker (10" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

17.For Variable Vapor Space Tanks:
Volume Expansion Capacity ______________________ (gallons)

18.Complete the following table for materials to be stored in this tank:

Material Stored	Annual Throughput (gal/yr)	Daily Average Amount Stored (gallons)	Material Molecular Weight (lb/lb-mole)	Material Vapor Pressure (psia)	Storage Pressure (psia)	Average Storage Temperature (°F)	Material Liquid Density (lb/gal)
#2 Fuel	35,360	1,700				Ambient	

19.Maximum Liquid Loading Rate of Tank:
___________________________ (gallons)

20.Can this tank be loaded at the same time other tanks are loaded? ______ Yes __✓_ No

If yes, indicate which other tanks can be loaded at the same time: _________________________

21.Describe the operations this tank will serve: **1,700-gallon fuel oil tank for emergency generator.**

T02

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S09	4. Unit identification number: EU09

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? _See Appendix C_

		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSIONS CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

T03

From December 2018 Application

State of Wisconsin
Department of Natural Resources

STACK IDENTIFICATION
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840	3. Stack identification number: S10

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 4530-109

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ____ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal ______ (ACFM) Maximum ______ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☒ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

T03

State of Wisconsin
Department of Natural Resources

From December 2018 Application

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-105 11-93 Information attached? __n_ (y/n)

SEE ATTACHED SHEET FOR INSTRUCTIONS

1.Facility Name: **Nemadji River Energy Center**

2.Facility Identification Number 816127840

3.Storage Tank Number: **EU10**

4.Control Device Number (use number from appropriate Form(s) 4530-110, 111, 112, 113, 114, 115, 116, or 117)

5.Storage Tank Capacity **180,000 gallons** gallons

6.Date of Installation or Last Modification ~~06/01/2021~~

7.Tank Height: 8.Tank Diameter:

3.5 ft x 3.5 ft x 5 ft Belly Tank (approximate specifications)

9.Color of Tank (check one)
_✓_ White __ Other___________________ __ Underground

10.Is this tank equipped with a submerged fill pipe?
_✓_ Yes __ No

11.Is this tank equipped with a pressure/vacuum conservation vent?
__ Yes _✓_ No

If yes; at what pressure is it set? ____________________(psia)
at what vacuum is it set? ____________________(psia)

12.Type of Storage Tank (check one)
__ Open Top Tank
__ Pressurized Tank
__ Fixed Roof
__ External Floating Roof
__ Fixed Roof w/Internal Floating Roof
__ Variable Vapor Space
_✓_ Other (specify) Generator belly tank___________

13.For all Fixed Roof Tanks:

a.Tank Configuration (check one): __ Vertical (upright cylinder) _✓_ Horizontal

b.Tank Roof Type (check one): (required if vertical was selected)
__ Cone Roof - Indicate tank roof height _____________(feet)
__ Dome Roof - Indicate tank roof height _____________(feet) - Indicate tank shell radius _____________(feet)

14.For all Floating Roof Tanks (both internal and external) - Shell Condition (check one):
__ Light Rust __ Dense Rust __Gunite Lined

15.For External Floating Roof Tanks:

a.Tank Construction (check one): __ Welded Tank __ Riveted Tank

b.Average Wind Speed at Tank Site: _________________________(mph)

c.Rim Seal System Description (check one):
__ Shoe Mounted Primary
__ Shoe Primary, Rim Secondary
__ Shoe Primary, Shoe Secondary
__ Vapor Mounted Primary
__ Vapor Primary, Rim Secondary
__ Vapor Primary w/Weather Shield
__ Liquid Mounted Primary
__ Liquid Primary, Rim Secondary
__ Liquid Primary w/Weather Shield

d.Roof Type (check one): __ Pontoon Roof __ Double Deck Roof

e.Roof Fitting Types (indicate the number of each type):

Access Hatch (24" diameter well)
____ Bolted cover, gasketed
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed

Unslotted guide-pole well (8" diameter unslotted pole, 21" diameter well)
____ Ungasketed sliding cover
____ Gasketed sliding cover

Gauge-float well (20" diameter)
____ Unbolted cover, ungasketed
____ Unbolted cover, gasketed
____ Bolted cover, gasketed

Gauge-Hatch/sample well (8" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Vacuum Breaker (10" diameter well)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

Roof Drain (3-inch diameter)
____ Open
____ 90% closed

Slotted guide-pole/sample well (8" diameter diameter slotted pole, 21" diameter well)
____ Ungasketed sliding cover, without float
____ Ungasketed sliding cover, with float
____ Gasketed sliding cover, without float
____ Gasketed sliding cover, with float

Roof leg (3" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double-deck roofs
____ Fixed

Roof leg(2-1/2" diameter)
____ Adjustable, pontoon area
____ Adjustable, center area
____ Adjustable, double deck roofs
____ Fixed

Continued on following page

State of Wisconsin
Department of Natural Resources
APPLICATION

STORAGE TANKS
AIR POLLUTION CONTROL PERMIT

Form 4530-105 11-93 Information attached?

(y/n)

16.For Internal Floating Roof Tanks:

a.Rim Seal System Description (check one): __ Vapor Mounted Primary __ Vapor Mounted Primary plus Secondary Seal
__ Liquid Mounted Primary __ Liquid Mounted Primary plus Secondary Seal

b.Number of Columns: _______________________________

c.Effective Column Diameter: _____________________ (feet)

d.Deck Type (check one): __ Welded __ Bolted

e.Total Deck Seam Length: _____________________ (feet)

f.Deck Area: ______________________ (square feet)

g.Deck Fitting Types (indicate the number of each type):

Access Hatch (24" diameter)
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Automatic gauge float well
____ Bolted cover, gasketed
____ Unbolted cover, gasketed
____ Unbolted cover, ungasketed

Ladder Well (36" diameter)
____ Sliding cover, gasketed
____ Sliding cover, ungasketed

Column Well (24" diameter)
____ Builtup column-sliding cover, gasketed
____ Builtup column-sliding cover, ungasketed
____ Pipe column-flexible fabric sleeve seal
____ Pipe column-sliding cover, gasketed
____ Pipe column-sliding cover, ungasketed

Sample pipe or well (24" diameter)
____ Slotted pipe-sliding cover, gasketed
____ Slotted pipe-sliding cover, ungasketed
____ Sample well-slit fabric seal 10% open area
____ Stub drain (1" diameter)

Roof leg or hanger well
____ Adjustable
____ Fixed

Vacuum breaker (10" diameter)
____ Weighted mechanical actuation, gasketed
____ Weighted mechanical actuation, ungasketed

17.For Variable Vapor Space Tanks:
Volume Expansion Capacity ______________________ (gallons)

18.Complete the following table for materials to be stored in this tank:

Material Stored	Annual Throughput (gal/yr)	Daily Average Amount Stored (gallons)	Material Molecular Weight (lb/lb-mole)	Material Vapor Pressure (psia)	Storage Pressure (psia)	Average Storage Temperature (°F)	Material Liquid Density (lb/gal)
No. 2 Fuel Oil	7,292	350				Ambient	

19.Maximum Liquid Loading Rate of Tank:
___________________________ (gallons)

20.Can this tank be loaded at the same time other tanks are loaded? ______ Yes _✓_ No

If yes, indicate which other tanks can be loaded at the same time: ____________

21.Describe the operations this tank will serve: **350 gallon tank stores No. 2 fuel oil for emergency fire pump engine tank.**

T03

From December 2018 Application

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93

Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: ~~To be assigned~~ 816127840
3. Stack identification number: S10	4. Unit identification number:EU10

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See Appendix C

		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSIONS CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

State of Wisconsin
STACK IDENTIFICATION
Department of Natural Resources

AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840	3. Stack identification number: NA

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 4530-109 F01

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ____ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal _________ (ACFM) Maximum ________ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☐ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

State of Wisconsin
Department of Natural Resources

MISCELLANEOUS PROCESSES
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-109 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Process number: F01

4a. Unit description: haul road fugitives

5. Indicate the control technology status. ☑ Uncontrolled ☐ Controlled

If the process is controlled, enter the control device number(s) from the appropriate form(s):

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Source Classification Code (SCC): 30502011

7. Date of construction or last modification: ~~TBD~~

8. Normal operating schedule: __24__ hrs./day __7__ days/wk. __365__ days/yr.

9. Describe this process (please attach a flow diagram of the process).	Attached?
Fugitive emissions from haul road truck traffic.	See next page.

10. List the types and amounts of raw materials used in this process:

Material	Storage/material handling process	Average usage	Units	Maximum usage	Units
N/A					

11. List the types and amounts of finished products:

Material	Storage/material handling process	Average amount produced	Units	Maximum amount produced	Units
N/A					

12. Process fuel usage:

Type of fuel	Maximum heat input to process million BTU/hr.	Average usage	Units	Maximum usage	Units
N/A					

13. Describe any fugitive emissions associated with this process, such as outdoor storage piles, unpaved roads, open conveyors, etc.: N/A	Attached? N/A

***** For this emissions unit, identify the method(s) of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F01

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☐ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s):

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☐ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s):

☐ Stack Testing - Form 4530-123
Pollutant(s):

☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s):

☑ Recordkeeping - Form 4530-125
Pollutant(s): $PM/PM_{10}/PM_{2.5}$

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 12 months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every 6 months thereafter.

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? n (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: 816127840

3. Stack identification number: NA

4. Unit identification number: F01

5. Pollutant(s) being monitored: $PM/PM_{10}/PM_{2.5}$

6. Material or parameter being monitored and recorded: Fugitive dust

7. Method of monitoring and recording:
Comply with fugitive dust control plan

8. List any EPA methods used: N/A

9. Is this an existing method of demonstrating compliance?
☐ Yes ☑ No

10. Installation date: ~~TBD~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☒ Monthly ☐ Batch (not to exceed monthly)

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application. *****

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately. *****

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center
2. Facility identification number: 816127840
3. Stack identification number: NA
4. Unit identification number: F01
5. Unit material description: PM, PM_{10}, $PM_{2.5}$ fugitives

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __no

		Units		Units		
NO HAPS EMISSIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93 Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F01

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See Appendix C

		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSION CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F01

		7. State Only		

	State Only	

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F01

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.
- ☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.
- ☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

6. For Units not presently fully in compliance, complete the following.
☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:

Start date: __________ and every six (6) months thereafter

State of Wisconsin
STACK IDENTIFICATION
Department of Natural Resources

AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-103 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840	3. Stack identification number: NA

4. Exhausting Unit(s), use Unit identification number from appropriate Form(s) 4530-104, 106, 107, 108 and/or 109

4530-104 4530-106 4530-107 4530-108 4530-109 F02

5. Identify this stack on the plot plan required on Form 4530-101

6. Indicate by checking:
☐ This stack has an actual exhaust point. ☑ This stack serves to identify fugitive emissions.

If this stack has an actual exhaust point, then provide the following stack parameters

7. Discharge height above ground level: ____ (feet)

8. Inside dimensions at outlet (check one and complete):

☐ Circular ____ (feet) ☐ rectangular ____ length (feet) ____ width (feet)

9. Exhaust flow rate:

Normal _________ (ACFM) Maximum ________ (ACFM)

10. Exhaust gas temperature (normal): ____ (°F)

11. Exhaust gas moisture content: Normal ____ volume percent Maximum ____ volume percent

12. Exhaust gas discharge direction: ☐ Up ☐ Down ☐ Horizontal

13. Is this stack equipped with a rainhat or any obstruction to the free flow of the exhaust gases from the stack? ☐ Yes ☐ No

***** Complete the appropriate Air Permit Application Forms(s) 4530-104, 106, 107, 108 or 109 for each Unit exhausting through this stack. *****

State of Wisconsin
Department of Natural Resources

MISCELLANEOUS PROCESSES
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-109 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Process number: F02

4a. Unit description: piping fugitives

5. Indicate the control technology status. ☑ Uncontrolled ☐ Controlled

If the process is controlled, enter the control device number(s) from the appropriate form(s):

4530-110 ____ 4530-111 ____ 4530-112 ____ 4530-113 ____
4530-114 ____ 4530-115 ____ 4530-116 ____ 4530-117

6. Source Classification Code (SCC): 30180001

7. Date of construction or last modification: ~~TBD~~

8. Normal operating schedule: __24__ hrs./day __7__ days/wk. __365__ days/yr.

9. Describe this process (please attach a flow diagram of the process).	Attached?
Fugitive emissions from piping components (valves, flanges, compressors, sampling connections and relief valves).	~~See next page.~~ Figures are at the end of Appendix A

10. List the types and amounts of raw materials used in this process:

Material	Storage/material handling process	Average usage	Units	Maximum usage	Units
N/A					

11. List the types and amounts of finished products:

Material	Storage/material handling process	Average amount produced	Units	Maximum amount produced	Units
N/A					

12. Process fuel usage:

Type of fuel	Maximum heat input to process million BTU/hr.	Average usage	Units	Maximum usage	Units
N/A					

13. Describe any fugitive emissions associated with this process, such as outdoor storage piles, unpaved roads, open conveyors, etc.: N/A	Attached? N/A

***** For this emissions unit, identify the method(s) of compliance demonstration by completing Form 4530-118, ***** DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE. Attach Form 4530-118 and its attachment(s) to this form. This is not a requirement of non-Part 70 sources.

***** Please complete the Air Pollution Control Permit Application Forms 4530-126 and 4530-128 for this Unit. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE CERTIFICATION - MONITORING AND REPORTING
DESCRIPTION OF METHODS USED FOR DETERMINING COMPLIANCE
Form 4530-118 11-93 Information attached? _n_ (y/n)

All applicants except non-Part 70 sources are required to certify compliance with all applicable air pollution permit requirements by including a statement within the permit application of the methods used for determining compliance (please see sec. NR 407.05(4)(i), Wis. Adm. Code.) This statement must include a description of the monitoring, recordkeeping, and reporting requirements and test methods. In addition, the application must include a schedule for compliance certification submittals during the permit term. These submittals must be no less frequent than annually, and may need to be more frequent if specified by the underlying applicable requirement or by the Department.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02

5. This Unit will use the following method(s) for determining compliance with the requirements of the permit (check all that apply and attach the appropriate form(s) to this form).

☐ Continuous Emission Monitoring (CEM) - Form 4530-119
Pollutant(s):

☐ Periodic Emission Monitoring Using Portable Monitors - Form 4530-120
Pollutant(s):

☐ Monitoring Control System Parameters or Operating Parameters of a Process - Form 4530-121
Pollutant(s):

☑ Monitoring Maintenance Procedures - Form 4530-122
Pollutant(s): GHG and VOC

☐ Stack Testing - Form 4530-123
Pollutant(s):

☐ Fuel Sampling and Analysis (FSA) - Form 4530-124
Pollutant(s):

☑ Recordkeeping - Form 4530-125
Pollutant(s): GHG and VOC

☐ Other (please describe) - Form 4530-135
Pollutant(s):

6. Compliance certification reports will be submitted to the Department according to the following schedule:

Start date: _At date of permit issuance_
and every __12__ months thereafter.

Compliance monitoring reports will be submitted to the Department according to the following schedule:

Start date: At date of permit issuance
and every __6__ months thereafter.

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY MONITORING MAINTENANCE PROCEDURES
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-122 11-93

Information attached? __ (y/n)

The monitoring of a maintenance procedure may be acceptable as a compliance demonstration method provided that a correlation between the procedure and the emission rate of a particular pollutant is established in the form of a curve of emission rate versus the frequency the procedure is performed. VOC leak detection programs or fugitive dust control programs are examples of procedures that could be monitored. The correlation shall be established using stack test data. This correlation shall constitute the certification of the monitoring system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the monitoring program.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center

2. Facility identification number: 816127840

3. Stack identification number: NA

4. Unit identification number: F02

5. Pollutant(s) being monitored: GHG and VOC

6. Procedure being monitored: GHG and VOC fugitives from piping components

7. Is this an existing maintenance procedure?
☐ Yes ☑ No

8. Installation date: ~~TBD~~

9. Method of monitoring: Quarterly and/or semi-annual inspection of equipment using instrumental methods, sight, sound, and smell.

10. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly - Quarterly and/or semi-annual inspection

11. Indicate by checking:

The monitoring program shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the monitoring program is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the monitoring program. ☐ The plan was submitted to the Department on _____.

***** Any failure to fulfill a maintenance requirement shall be reported as an excess emission. *****

State of Wisconsin
Department of Natural Resources

COMPLIANCE DEMONSTRATION BY RECORDKEEPING
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-125 11-93

Information attached? n (y/n)

Recordkeeping may be acceptable as a compliance demonstration method provided that a correlation between the parameter value recorded and the emission rate of a particular pollutant is established in the form of a curve or chart of emission rate versus parameter values. This correlation may constitute the certification of the system. It should be attached for Department approval. If it is not attached, please submit it within 60 days of the startup of the system.

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02
5. Pollutant(s) being monitored: GHG and VOC	6. Material or parameter being monitored and recorded: GHG and VOC fugitives from piping components

7. Method of monitoring and recording:
Per plan, comply with inspection of equipment using instrumental methods, sight, sound, and smell.

8. List any EPA methods used: N/A

9. Is this an existing method of demonstrating compliance? ☐ Yes ☑ No	10. Installation date: ~~TBD~~

11. Backup system: N/A

12. Compliance shall be demonstrated: ☐ Daily ☐ Weekly ☐ Monthly ☐ Batch (not to exceed monthly)
Applicant proposes quarterly and/or semi-annual compliance demonstrations

13. Indicate by checking:

The monitoring system shall be subject to appropriate performance specifications, calibration requirements, and quality assurance procedures. ☐ A quality assurance/quality control plan for the recordkeeping system is attached for Department approval. ☑ If the plan is not attached, please submit it within 60 days of the startup of the recordkeeping program. ☐ The plan was submitted to the Department on _____.

***** The compliance records shall be available for Department inspection. The format for the compliance ***** certification report and the excess emission report shall be approved by the Department. A proposed format for the compliance certification report and excess emission report shall be submitted at the same time as the application.

***** The source shall record any malfunction that causes or may cause an emission limit to be exceeded. ***** Malfunctions shall be reported to the Department the next business day. Hazardous air spills shall be reported to the Department immediately.

State of Wisconsin
Department of Natural Resources

EMISSION UNIT HAZARDOUS AIR POLLUTANT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-126 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02
5. Unit material description: Piping fugitives (GHG and VOC)	

6. Complete the following summary of hazardous air emissions from this unit. Attach sample calculations and emission factor references. Attached? __no

		Units		Units		
NO HAPS EMISSIONS						
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY
						TPY

State of Wisconsin
Department of Natural Resources

EMISSION UNIT SUMMARY
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-128 11-93 Information attached? _y_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02

5. Complete the following emissions summary for the following pollutants. Attach sample calculations and emission factor references. Attached? __See Appendix C

		U	TPY		U	TPY				U	TPY

SEE APPENDIX C FOR EMISSION CALCULATIONS

Sulfur dioxide								TPY			
Organic compounds								TPY			
Carbon monoxide								TPY			
Lead								TPY			
Nitrogen oxides								TPY			
Total reduced sulfur								TPY			
Mercury								TPY			
Asbestos								TPY			
Beryllium								TPY			
Vinyl chloride								TPY			
								TPY			
								TPY			
								TPY			
								TPY			
								TPY			

Units (U) should be entered as follows:

1 = lb/hr
2 = lb/mmBTU
3 = grains/dscf
4 = lb/ gallon
5 = ppmdv
6 = other (specify)
7 = other (specify)
8 = other (specify)

State of Wisconsin
Department of Natural Resources

CURRENT EMISSIONS REQUIREMENTS AND STATUS OF UNIT
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-130 Rev. 12-99 Information attached? n (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02

		7. State Only		

	State Only	

** **PART 70 SOURCES ONLY:**

1. **Be sure to review the Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, for the Renewal Application.** The CAM rule requires owners and operators of Part 70 sources to monitor the operation and maintenance of their control equipment so that they can evaluate the performance of their control devices and report whether or not their facilities meet established emission standards. All facilities that have a Title V, Part 70, Federal Operating Permit are required to meet the CAM rule and **submit a CAM plan with this Title V renewal application.** The rule requires that a CAM plan be submitted with the Title V renewal application for each pollutant at **each emissions unit** which has a potential to emit - prior to controls - of that pollutant greater than the major source threshold for the respective pollutant. Please refer to the CAM Technical Guidance web site at http://www.epa.gov/ttn/emc/cam.html for further documentation on the rule and how to prepare a CAM plan for submittal with the renewal application.
2. List all applicable **Maximum Achievable Control Technology** (MACT) rule(s) and the effective date(s) if they were promulgated during the last 3 years of your operation permit term. Identify the emissions units subject to each MACT rule listed.

State of Wisconsin
Department of Natural Resources

EMISSION UNIT COMPLIANCE PLAN
COMMITMENTS AND SCHEDULE
AIR POLLUTION CONTROL PERMIT APPLICATION
Form 4530-131 11-93 Information attached? _n_ (y/n)

SEE INSTRUCTIONS ON REVERSE SIDE

1. Facility name: Nemadji Trail Energy Center	2. Facility identification number: 816127840
3. Stack identification number: NA	4. Unit identification number: F02

5. For Units that are presently in compliance with all applicable requirements, including any enhanced monitoring and compliance certification requirements under section 114(a)(3) of the Clean Air Act that apply, complete the following. These commitments are part of the application for Part 70 permits.
- ☐ We will continue to operate and maintain this Unit in compliance with all applicable requirements.
- ☑ Form 4530-130 includes new requirements that apply or will apply to this Unit during the term of the permit. We will meet such requirements on a timely basis.

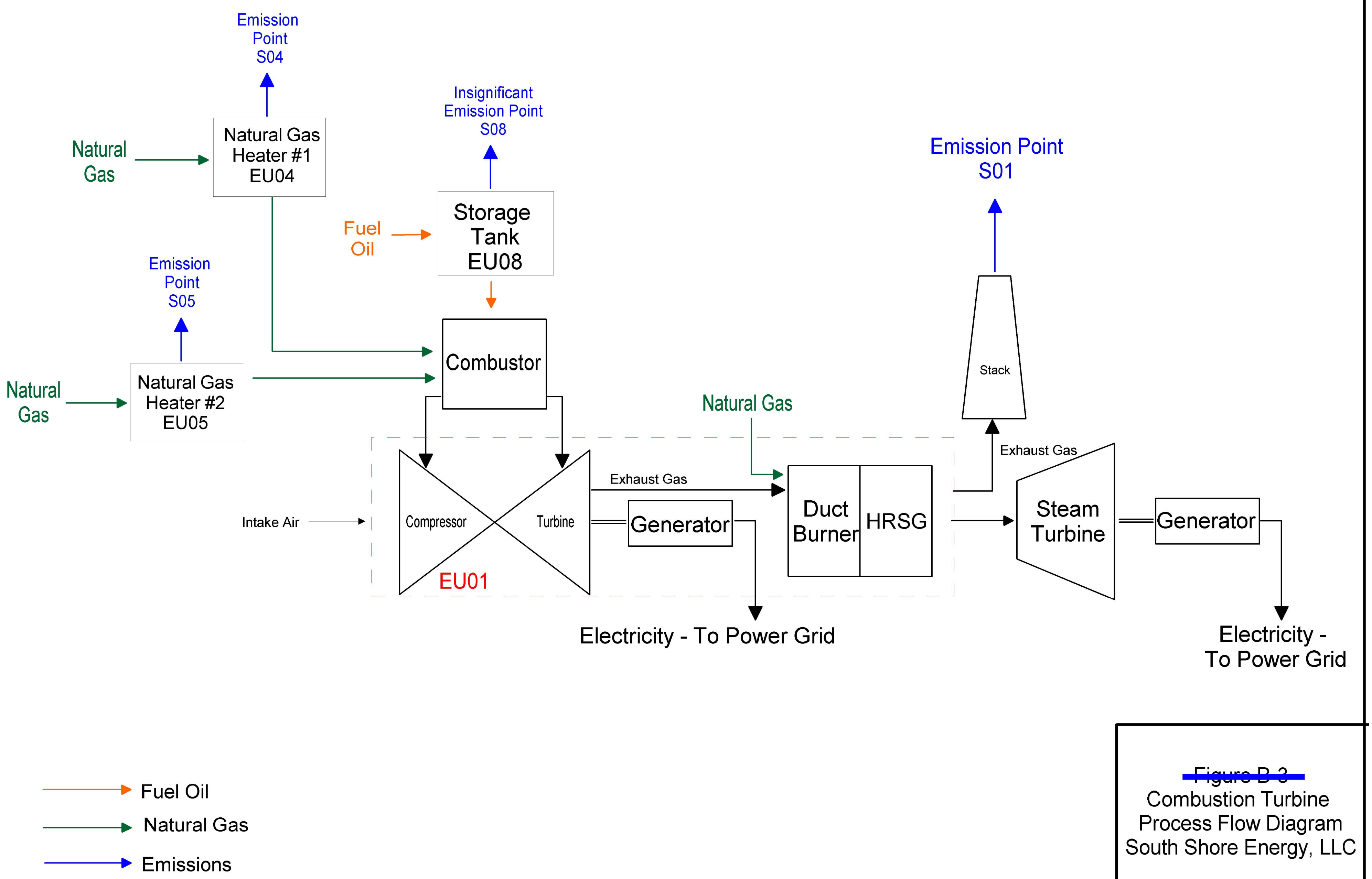
6. For Units not presently fully in compliance, complete the following.
☐ This Unit is in compliance with all applicable requirements except for those indicated below. We will achieve compliance according to the following schedule:

Applicable Requirement	Corrective Actions	Deadline
1.		
2.		
3.		

Progress reports will be submitted:

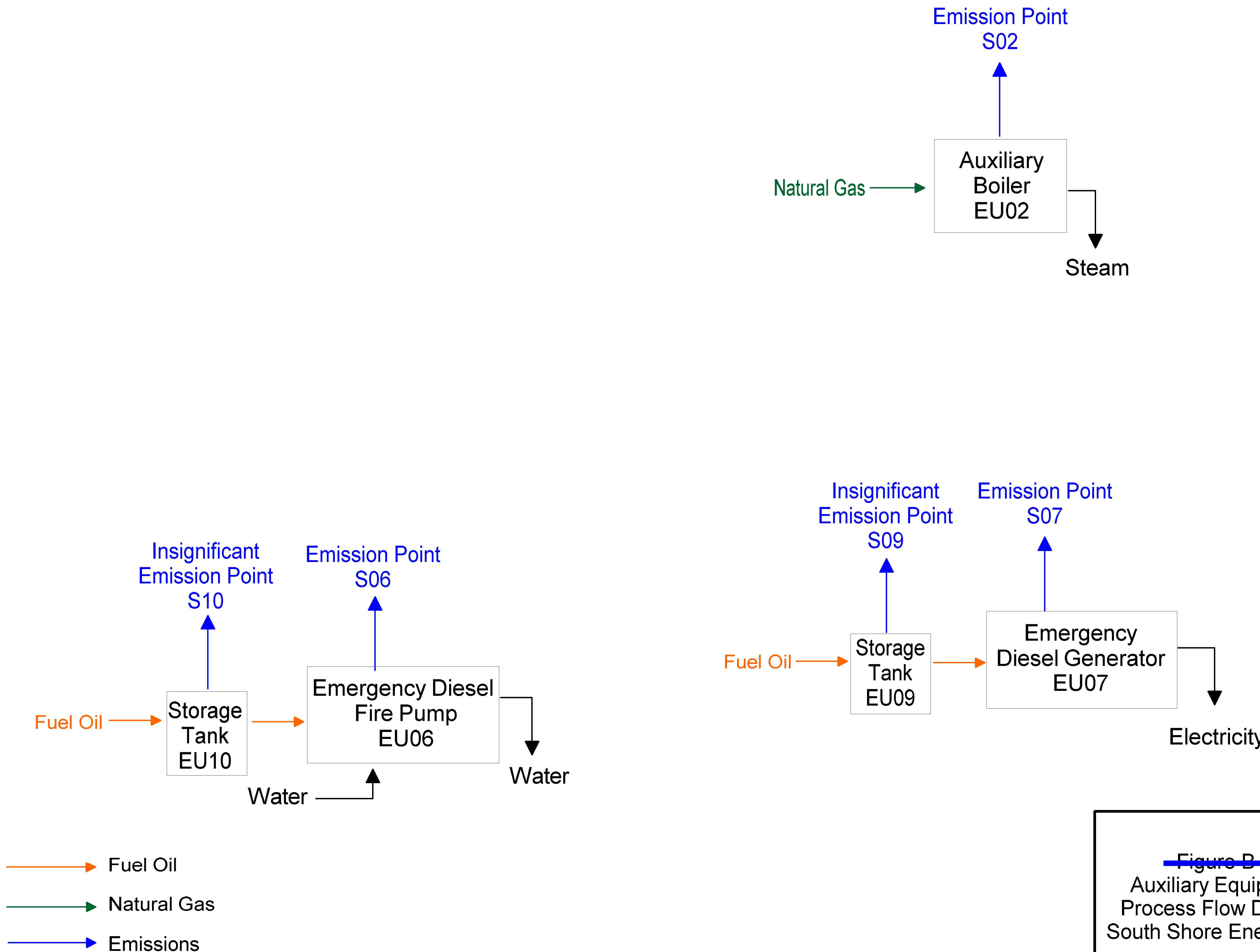
Start date: ___________ and every six (6) months thereafter

From December 2018 Application



~~Figure B-3~~
Combustion Turbine
Process Flow Diagram
South Shore Energy, LLC

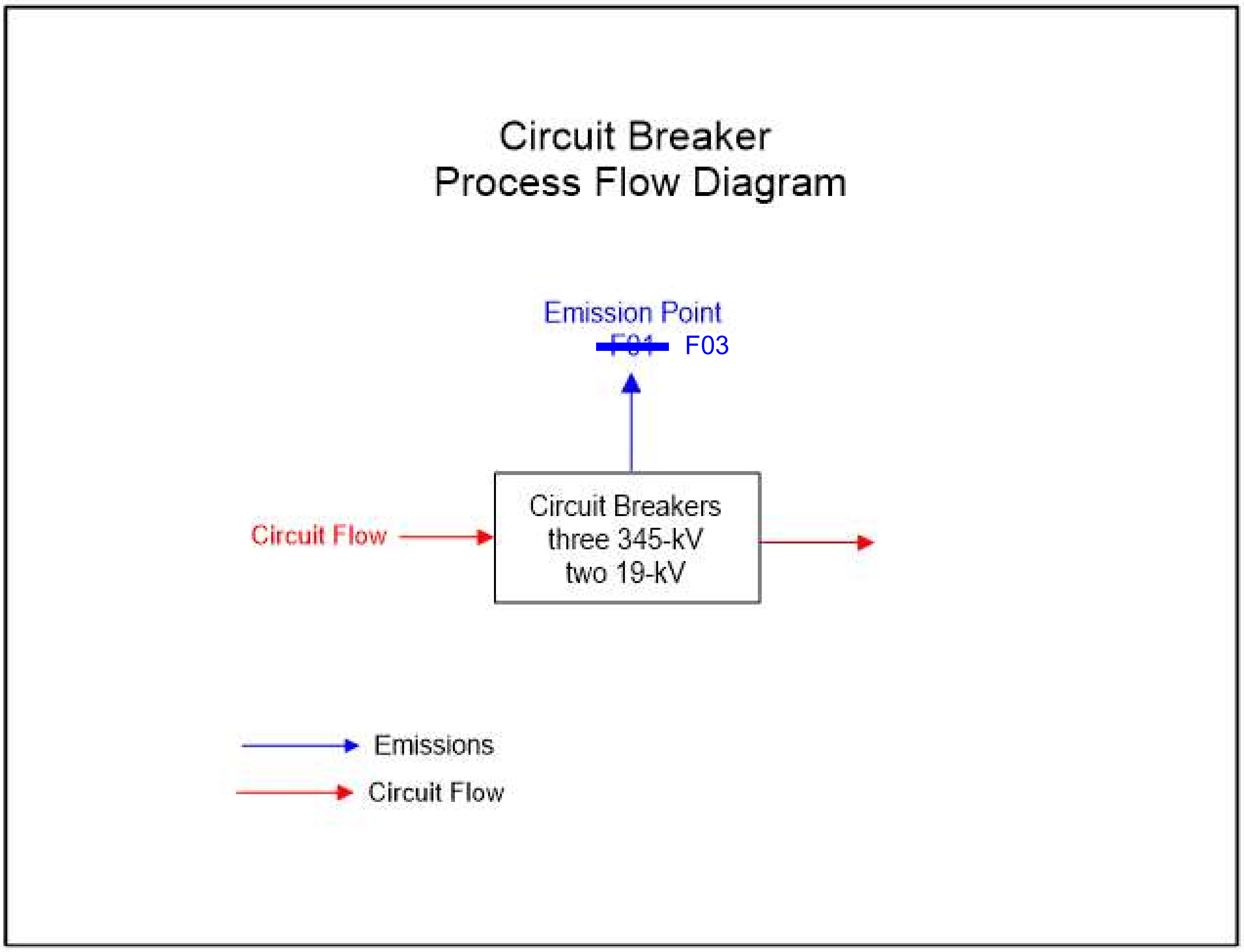
From December 2018 Application

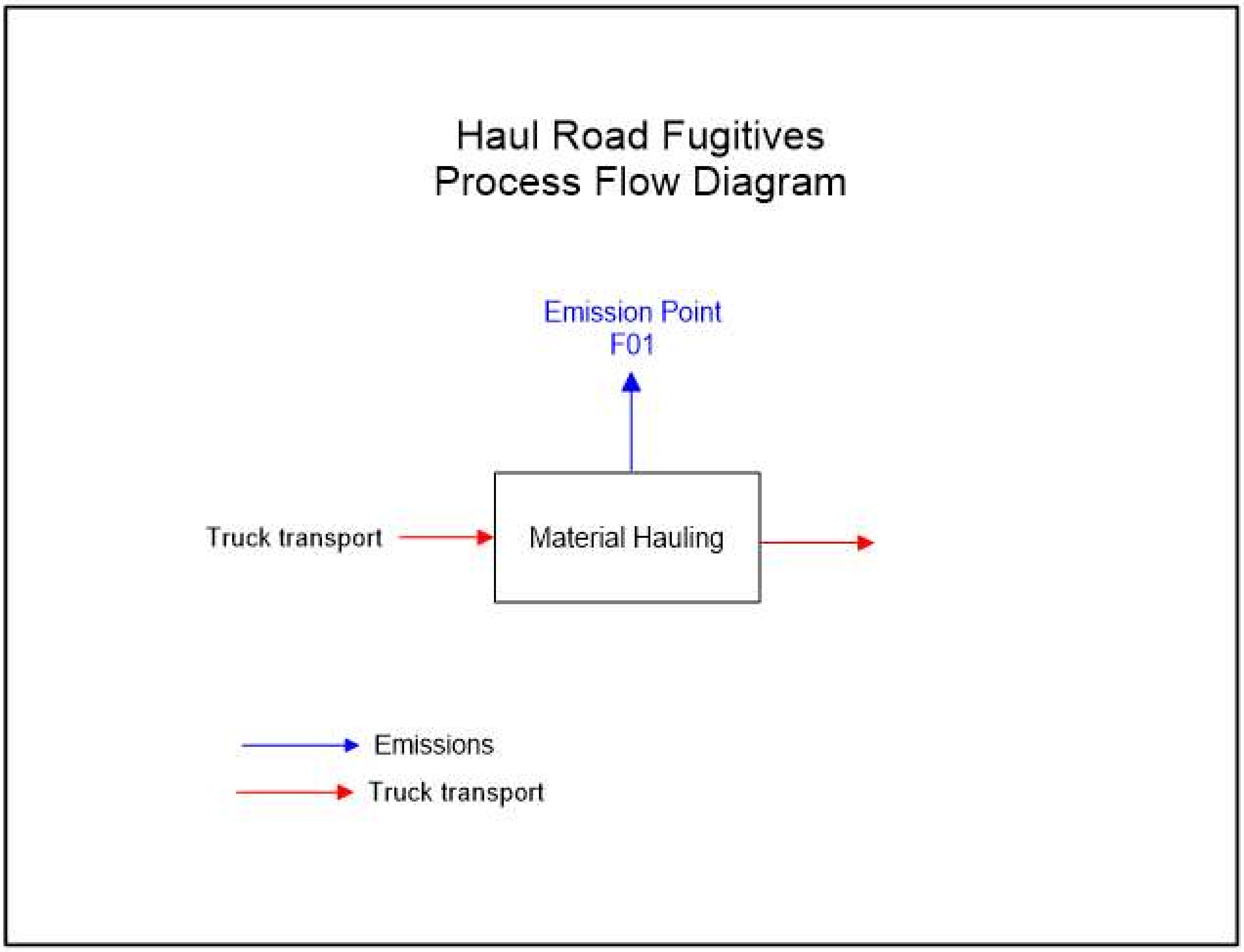


~~Figure B-4~~
Auxiliary Equipment
Process Flow Diagram
South Shore Energy, LLC

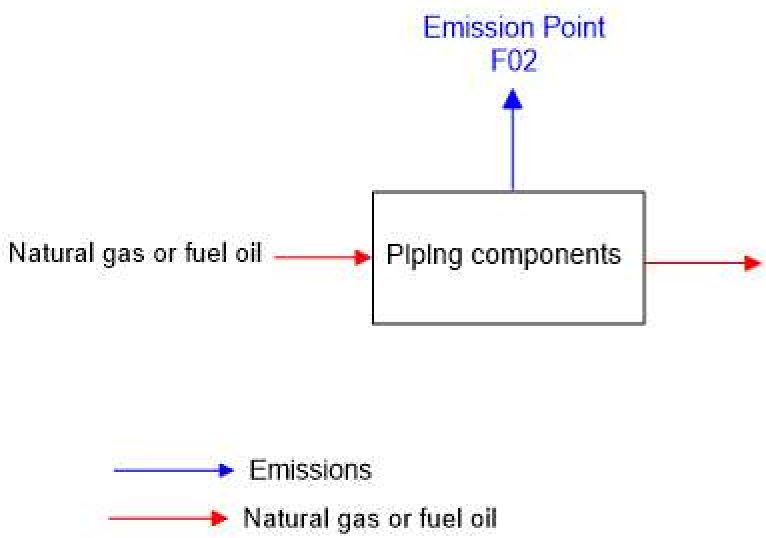
F03

From June 2020 Application




Haul Road Fugitives
Process Flow Diagram
Emission Point
F01
Truck transport
Material Hauling
Emissions
Truck transport

Natural Gas and Fuel Oil Piping Fugitives Process Flow Diagram



APPENDIX B – FIGURES

Path: Z:\Clients\ENS\SouthShoreEn\101798_NTECGeneration\Studies\Geospatial\DataFiles\ArcDocs\Air_Permit_Application\Figure_B_1_Nemadji_Location.mxd kasamuelson 12/10/2018

★ Preferred Site

Nemadji River Site Boundary

State Boundary

County Boundary

NORTH

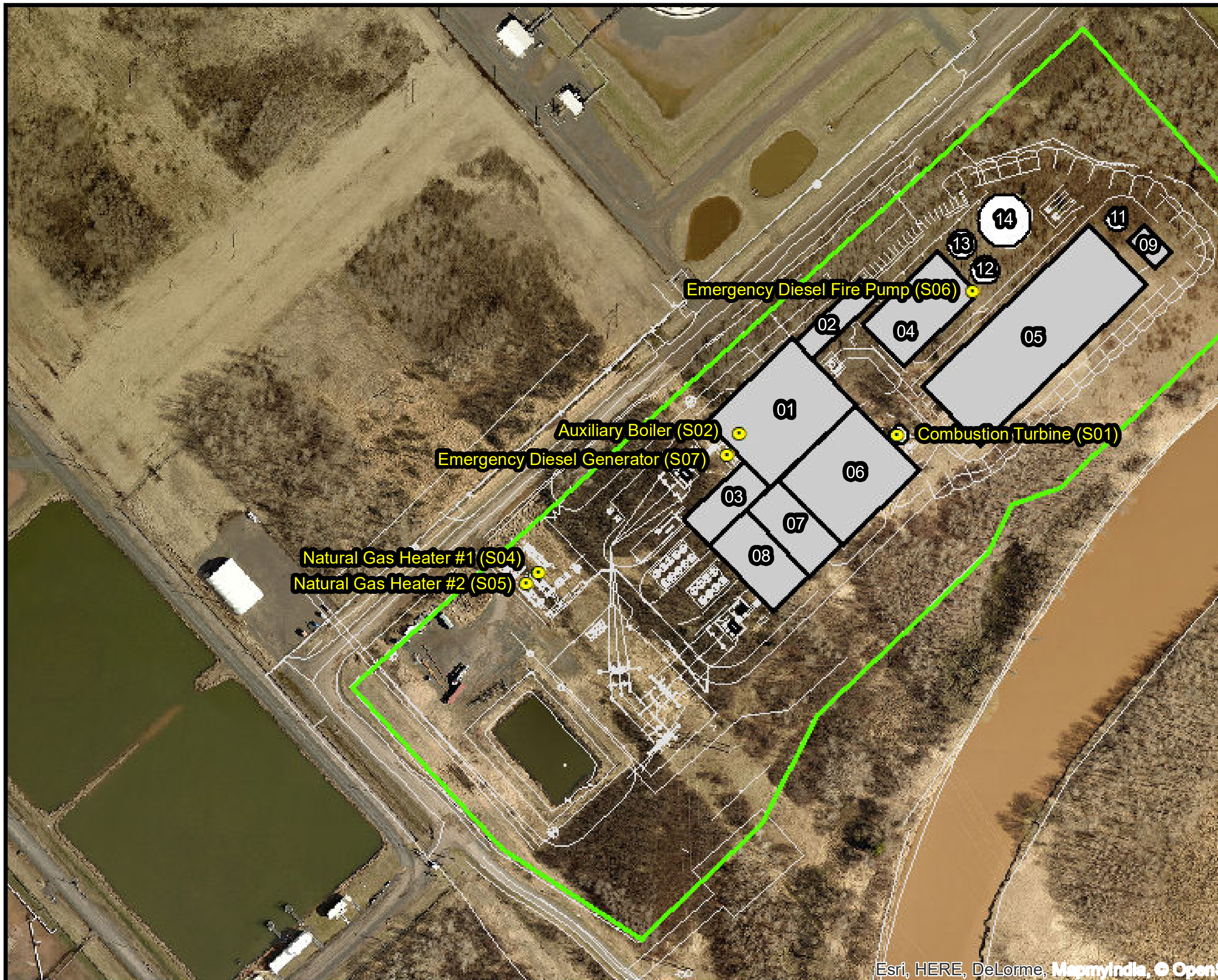
0 0.5 1
Kilometers

Figure B-1
Nemadji Trail Energy Center
Project Location
South Shore Energy, LLC

Source: ESRI, NAIP Douglas County 2015, Burns & McDonnell Engineering Company, Inc.

Issued: 12/10/2018

Path: \\bmcd\Dfs\Clients\ENS\SouthShoreEn\101798_NTECGeneration\Studies\Permitting\Modeling\Air\Layouts\Primary\Figure B-2 Facility Plot Plan Nemadji 05-21-20.mxd gweger 5/26/2020



Building Legend
01 - Steam Turbine Building - 100 ft
02 - Admin Building - 36 ft
03 - Warehouse Building - 30 ft
04 - Water Treatment Building - 28 ft
05 - ACC - 98 ft
06 - HRSG Building - 120 ft
07 - Combustion Turbine Building - 91 ft
08 - Combustion Turbine Building - 42 ft
09 - Ammonia/Fuel Oil Pump Building - 12 ft

Tank Legend
11 - Fuel Oil Tank - 40 ft
12 - Service Water Tank - 40 ft
13 - Demin Water Tank - 40 ft
14 - Demin Water Tank - 40 ft

Emission Sources
Fence Line
Tanks
Buildings

NORTH

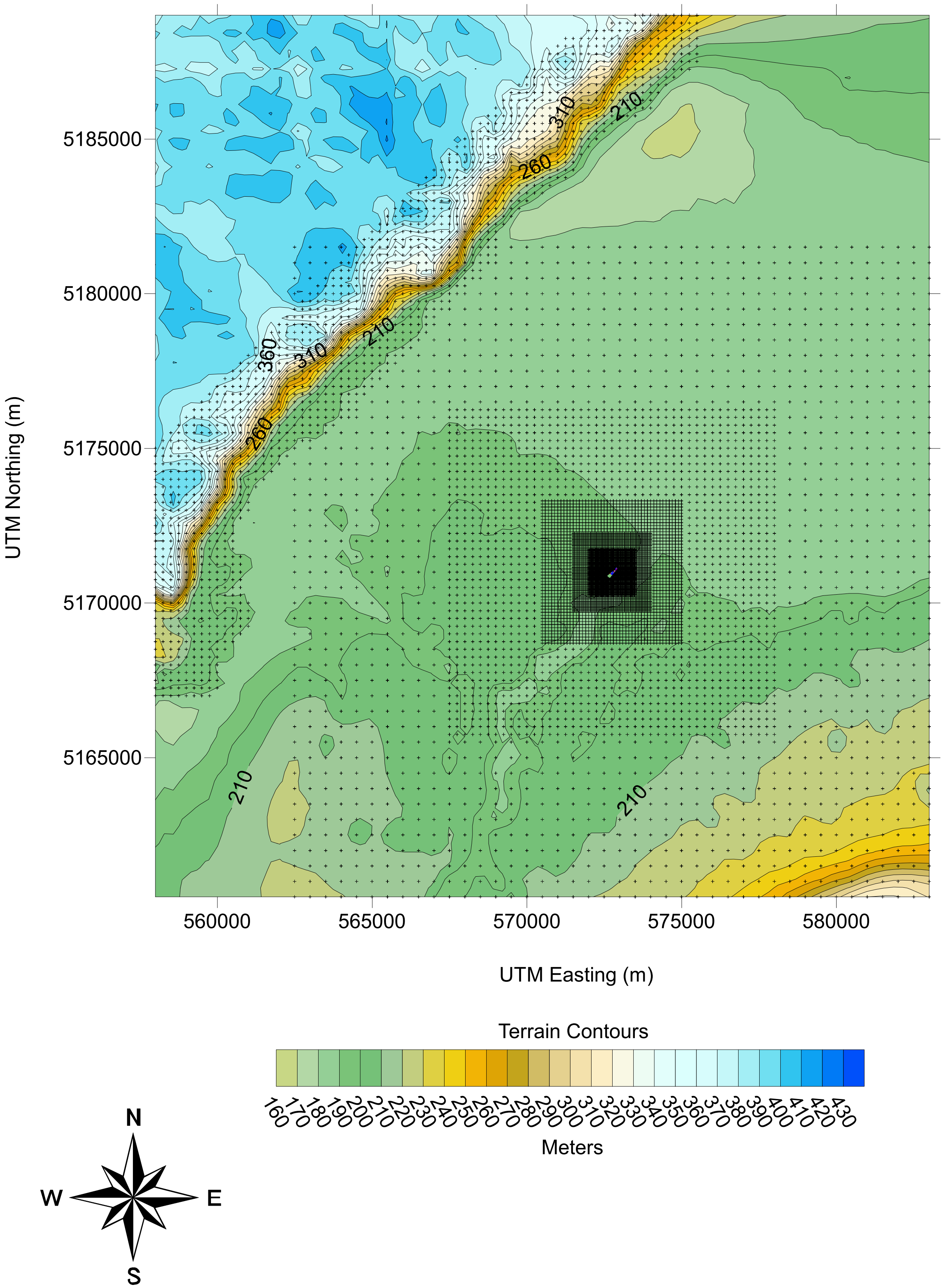
250 125 0 250
Scale in Feet

Figure B-2
Nemadji Trail Energy Center
Facility Plot Plan
South Shore Energy, LLC

Source: ESRI, and Burns & McDonnell Engineering Company, Inc.

Issued: 5/26/2020

Figure B-3: 20 km by 20 km Receptor Grid and Elevation Map



Path: Z:\Clients\ENS\SouthShoreEn\101798_NTECGeneration\Studies\Geospatial\DataFiles\ArcDocs\Air_Permit_Application\Figure_G_2_Nemadji_Primary_Land_Use.mxd kasamuelson 12/10/2018

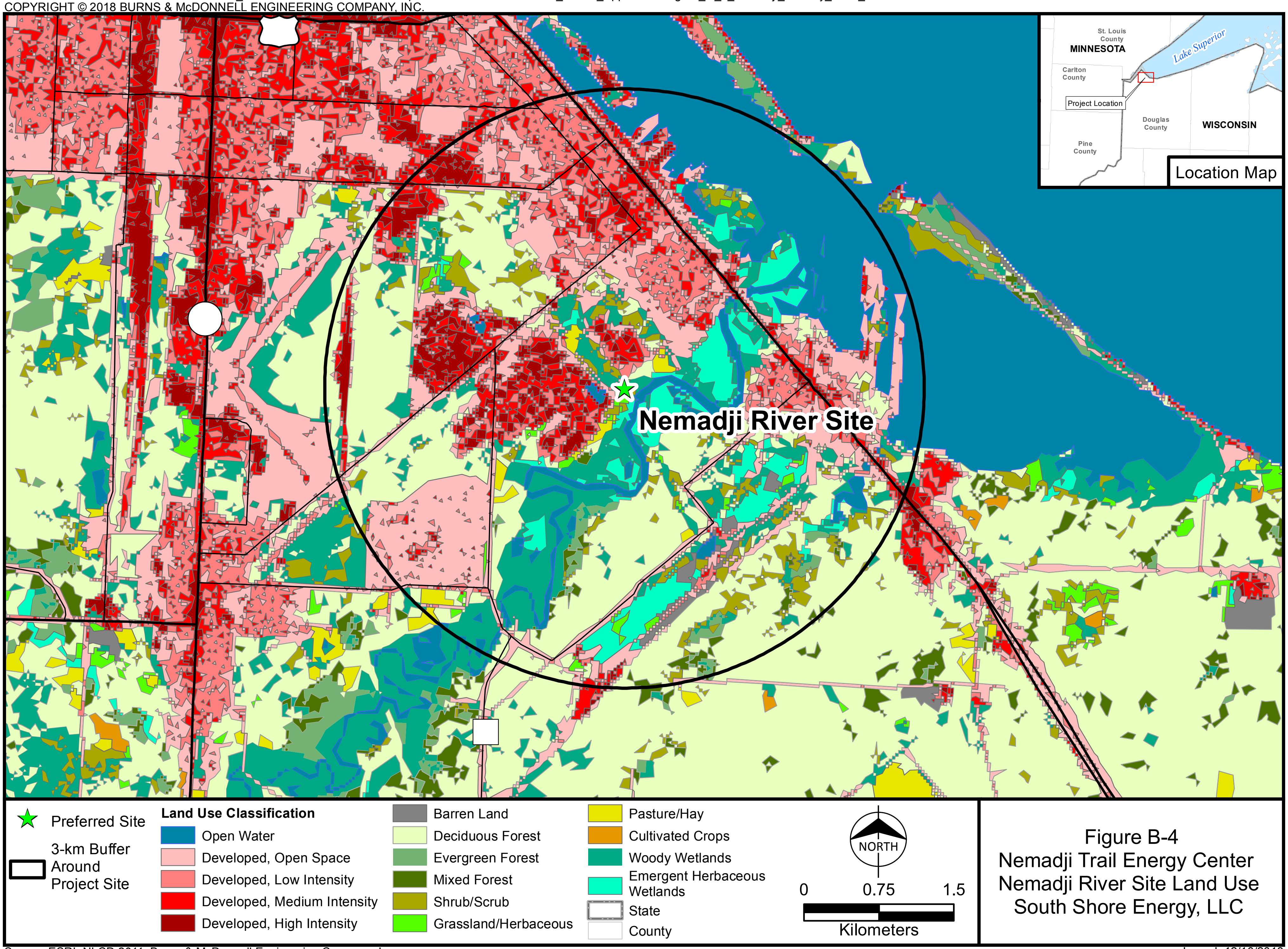


Figure B-4
Nemadji Trail Energy Center
Nemadji River Site Land Use
South Shore Energy, LLC

Source: ESRI, NLCD 2011, Burns & McDonnell Engineering Company, Inc.

Issued: 12/10/2018

Path: Z:\Clients\ENS\SouthShoreEn\101798_NTECGeneration\Studies\Geospatial\DataFiles\ArcDocs\Air_Permit_Application\Figure_G_3_Nemadji_ClassI_Areas.mxd kasamuelson 12/10/2018

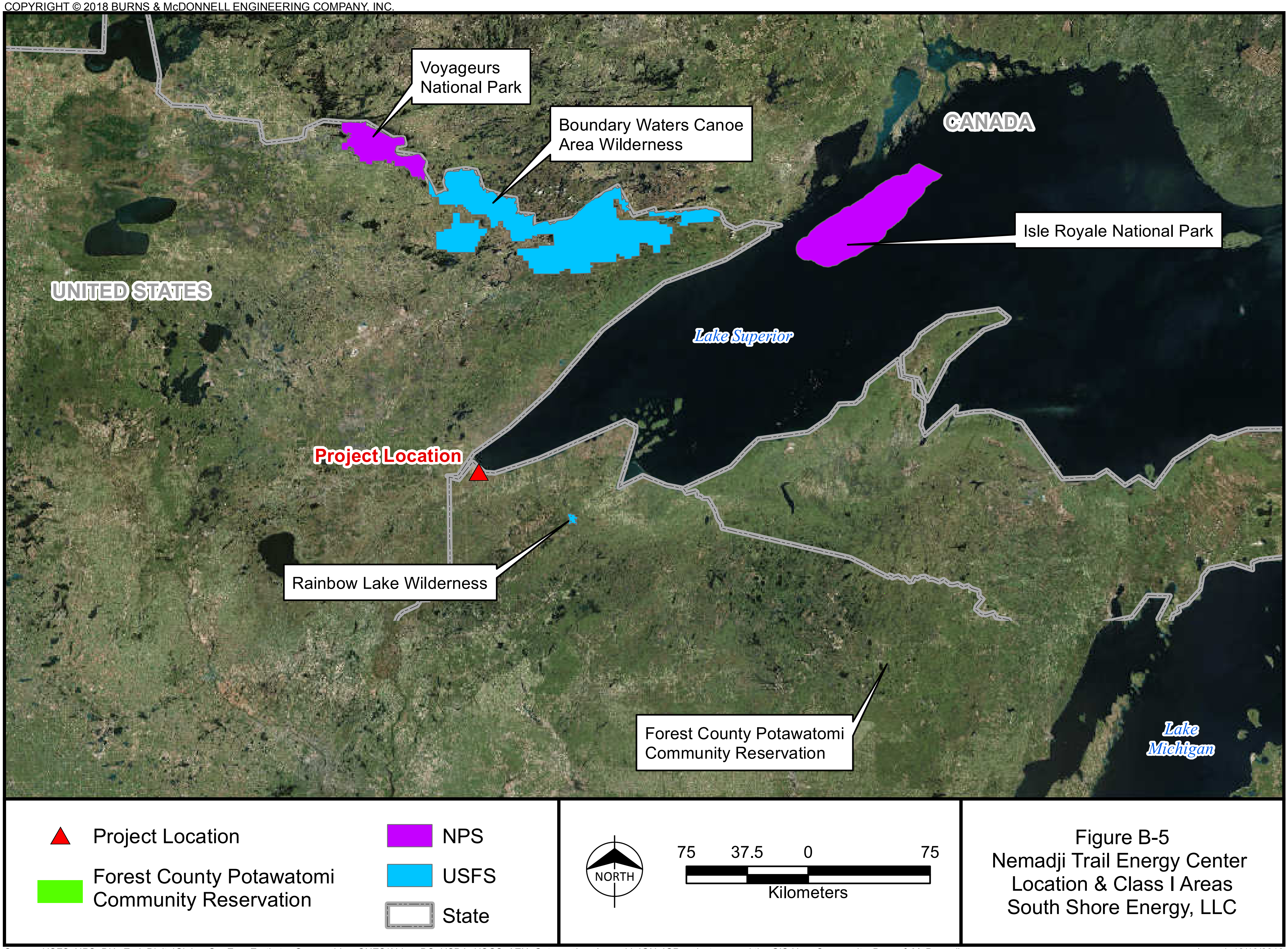


Figure B-5
Nemadji Trail Energy Center
Location & Class I Areas
South Shore Energy, LLC

Source: USFS; NPS; BIA; Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community; Burns & McDonnell.

Issued: 12/10/2018

APPENDIX C – CALCULATIONS

1/28/2022 Revision

South Shore Energy, LLC - Nemadji Trail Energy Center
Project Emissions

Maximum Facility Emissions

Pollutant	Permitted Potential Emissions[a] (tpy)	Project Potential Emissions[b] (tpy)	Total Facility Potential Emissions (tpy)
NO_x	269.1	--	269
CO	2,002.52	--	2,003
PM	166.9	0.10	167
PM_{10}	166.9	0.02	167
$PM_{2.5}$	166.9	0.005	167
SO_2	28.7	--	29
VOC	239	10.4	250
H_2SO_4	43.2	--	43
Lead	0.0	--	0.01
CO_2e	2,738,317.8	976.6	2,739,294

(a) Construction Permit Number: 18-MMC-168
(b) Construction Permit Number: 21-MMC-011

Maximum Annual Emission Rates

	Construction Permit Number: 18-MMC-168								Construction Permit Number: 21-MMC-011			
Pollutant	**P01 Combined-Cycle Combustion Turbine[a] (tpy)**	**B02 Auxiliary Boiler (tpy)**	**P04 Natural Gas Heater #1 (tpy)**	**P05 Natural Gas Heater #2 (tpy)**	**P06 Emergency Diesel Fire Pump (tpy)**	**P07 Emergency Diesel Generator (tpy)**	**T01, T02, T03 Storage Tanks (tpy)**	**F03 Circuit Breakers (tpy)**	**F01 Haul Road Fugitives (tpy)**	**F02 Piping Fugitives (tpy)**	**Total[b] (tpy)**	**PSD Significant Emission Rates (tpy)**
NO_x	255.6	4.8	2.1	2.1	0.5	3.9	--	--	--	--	**269**	40
CO	1,991.1	1.6	3.6	3.6	0.4	2.1	--	--	--	--	**2,003**	100
PM	162.8	3.3	0.3	0.3	0.02	0.1	--	--	0.10	--	**167**	25
PM_{10}	162.8	3.3	0.3	0.3	0.02	0.1	--	--	0.02	--	**167**	15
$PM_{2.5}$	162.8	3.3	0.3	0.3	0.02	0.1	--	--	0.005	--	**167**	10
SO_2	28.2	0.3	0.03	0.03	0.1	4.5.E-03	--	--	--	--	29	40
VOC	237.3	1.2	0.2	0.2	0.2	0.3	0.04	--	--	10.4	**250**	40
H_2SO_4	43.2	0.04	3.9.E-03	3.9.E-03	0.02	6.9.E-04	--	--	--	--	**43**	7
Lead	0.01	2.1.E-04	4.3.E-05	4.3.E-05	--	--	--	--	--	--	0.01	0.6
CO_2e	2,675,731	51,289	5,129	5,129	80	841	--	120	--	977	**2,739,294**	75,000

(a) Represents worse-case emissions scenario
(b) Numbers in bold indicate the PSD significance level is exceeded

Assumptions		
Unit	**Limitation**	**Units**
Turbine	8,760	Natural gas hours per year
	50	Number of natural gas cold starts per year
	150	Number of natural gas warm starts per year
	900	Number of natural gas hot/fast starts per year
	1,100	Total number of combined natural gas start-ups per year (cold/warm/hot/fast)
	1,100	Total number of natural gas shutdowns per year
	1,525.0	Hours of natural gas Startup/Shutdown per year
	500	Fuel oil hours per year with or without duct burning
	11,025,196	gallons/year fuel oil
	42	Number of fuel oil startup/shutdowns per year
	105.0	Hours of fuel oil Startup/Shutdown
Natural Gas Duct Firing	8,760	Hours per year
Auxiliary Boiler	8,760	Hours per year
~~Cooling Tower~~	~~8,760~~	~~Hours per year~~
Natural Gas Heater #1	8,760	Hours per year
Natural Gas Heater #2	8,760	Hours per year
Emergency Diesel Fire Pump	500	Hours per year
Emergency Diesel Generator	500	Hours per year
Fuel oil heating value	137,000	Btu/gal

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine

	Natural Gas			
Pollutants	Duct Burning lb/hr	100 lb/hr	75 lb/hr	Minimum Emissions Compliance Load lb/hr
NO_X	33.5	26.5	20.6	12.4
CO	15.3	12.1	9.4	5.7
$PM/PM_{10}/PM_{2.5}$	36.3	21.8	16.8	12.9
SO_2	6.4	5.1	4.0	2.4
VOC	15.5	2.8		
H_2SO_4	9.9	7.8		
Lead	0.0	0.0		
CO_2	495,325	392,985		
N_2O	303.5	240.8		
CH_4	254.6	202.0		
CO_2e (sum)	592,127	469,787		
Temperature	163.55	167.12	164.93	164.93
Velocity	64.00	63.81	48.88	36.82

	Fuel Oil			
Pollutants	Duct Burning lb/hr	100 lb/hr	75 lb/hr	Minimum Emissions Compliance Load lb/hr
NO_X	72.7	51.6	41.0	31.1
CO	11.1	7.8	6.2	15.8
$PM/PM_{10}/PM_{2.5}$	54.5	39.4	37.5	35.7
SO_2	6.1	4.6	3.6	2.8
VOC	14.1	1.8		
H_2SO_4	9.3	7.0		
Lead	0.04	0.04		
CO_2	559,613	452,619		
N_2O	1,256.3	1,190.8		
CH_4	554.4	499.5		
CO_2e (sum)	947,846	819,965		
Temperature	176.63	176.63	169.24	165.01
Velocity	71.96	71.19	57.75	43.48

Natural Gas Startup/Shutdown Emissions

Pollutant	Start-up Emissions (lb/cold start)[b,d]	Start-up Emissions (lb/warm start)[b, d]	Start-up Emissions (lb/hot-fast start)[b, d]	Shutdown Emissions (lb/shutdown)[c]	Start-up/ Shutdown Emissions (tpy)
NOx[a]	335.0	233.0	111.0	59.0	108.3
CO[a]	11,066	6,495	779.0	463.0	1,369
$PM/PM_{10}/PM_{2.5}$	43.6	29.1	16.3	10.9	16.6
SO_2	10.2	6.8	3.8	2.6	3.9
VOC[a]	950.0	558.0	67.0	40.0	117.8
H_2SO_4	15.6	10.4	5.9	3.9	6.0
Lead	0.0	0.0	0.0	0.0	0.0
CO_2	785,971	523,981	294,739	196,493	299,651
N_2O	482	321	181	120	184
CH_4	404	269	151	101	154
CO_2e	939,573	626,382	352,340	234,893	358,212

(a) Start-up emissions based on vendor load and startup profiles
(b) Cold start-up period is 2 hours, warm start-up period is 80 minutes, hot/fast start-up period is 45 minutes
(c) Shutdown emissions from "startup summary" (assumes half hour)
(d) Emissions are based on 1525 hours spent in start-up/shutdown operation

Fuel Oil Startup/Shutdown Emissions

Pollutant	Start-up Emissions (lb/cold start)[b]	Shutdown Emissions (lb/shutdown)[c]	Number of Starts Per Turbine	Start-up/ Shutdown Emissions (tpy)
NOx[a]	860.0	108.0	42	20.3
CO[a]	25,846	1,227	42	568.5
$PM/PM_{10}/PM_{2.5}$	78.9	19.7	42	2.1
SO_2	9.2	2.3	42	0.2
VOC[a]	2,951	122.0	42	64.5
H_2SO_4	14.0	3.5	42	0.4
Lead	0.08	0.02	42	0.002
CO_2	905,239	226,310	42	23,763
N_2O	2,382	595	42	63
CH_4	999	250	42	26
CO_2e	1,639,929	409,982	42	43,048

(a) Start-up emissions based on vendor load and startup profiles
(b) Start-up emissions are 2 hours.
(c) Shutdown emissions from "startup summary" (assumes half hour)

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine Emissions

DB= Duct Burning
NG= Natural Gas
SUSD= Startup Shutdown
FO=Fuel Oil

	Hours						
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7
DB NG	8,760	7,235	6,735	0	0	8,260	6,735
NG	0	0	0	7,235	6,735	0	0
NG SUSD	0	1,525	1,525	1,525	1,525	0	1,525
DB FO	0	0	0	0	0	395	395
FO	0	0	395	0	395	0	0
FO SUSD	0	0	105	0	105	105	105
Total Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760

	DB NG	NG 100	DB FO	FO 100	NG Start-up/Shutdown Emissions	FO Start-up/Shutdown Emissions
Pollutant	**lb/hr**	**lb/hr**	**lb/hr**	**lb/hr**	**tpy**	**tpy**
NO_X	33.5	26.5	72.7	51.6	108.3	20.3
CO	15.3	12.1	11.1	7.8	1,369.0	568.5
$PM/PM_{10}/PM_{2.5}$	36.3	21.8	54.5	39.4	16.6	2.1
SO_2	6.4	5.1	6.1	4.6	3.9	0.2
VOC	15.5	2.8	14.1	1.8	117.8	64.5
H_2SO_4	9.9	7.8	9.3	7.0	6.0	0.4
Lead	0.0	0.0	0.042	0.042	0.0	0.002
CO_2	495,325	392,985	559,613	452,619	299,651	23,763
N_2O	303.5	240.8	1,256.3	1,190.8	184	63
CH_4	254.6	202.0	554.4	499.5	154	26
CO_2e (sum)	592,127	469,787	947,846	819,965	358,212	43,048

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Maximum
Pollutant	**tons per year**							
NO_X	146.5	229.3	251.4	204.3	228.2	172.9	**255.6**	255.6
CO	66.9	1,424.2	1,990.5	1,412.8	1,979.9	633.8	**1,991.1**	1,991.1
$PM/PM_{10}/PM_{2.5}$	159.0	148.0	148.8	95.5	99.9	**162.8**	151.7	162.8
SO_2	**28.2**	27.2	26.7	22.4	22.2	28.0	27.0	28.2
VOC	68.0	173.9	234.9	127.8	192.0	131.4	**237.3**	237.3
H_2SO_4	**43.2**	41.6	40.9	34.3	34.1	42.9	41.4	43.2
Lead	0.00	0.00	**0.01**	0.00	**0.01**	**0.01**	**0.01**	0.01
CO_2	2,169,524	2,091,490	2,080,813	1,721,276	1,736,185	**2,179,979**	2,101,945	2,179,979
N_2O	1,329	1,281	1,503	1,055	1,292	**1,564**	1,516	1,564
CH_4	1,115	1,075	1,136	885	959	**1,187**	1,147	1,187
CO_2e (sum)	2,593,514	2,500,230	2,557,190	2,057,666	2,145,210	**2,675,731**	2,582,446	2,675,731

Scenario 1	Hours
DB NG	8,760
NG	0
NG SSSD	0
DB FO	0
FO	0
FO SUSD	0
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**	**tpy**
NO_X	146.5	0.0	0.0	0.0	0.0	0.0	146.5
CO	66.9	0.0	0.0	0.0	0.0	0.0	66.9
$PM/PM_{10}/PM_{2.5}$	159.0	0.0	0.0	0.0	0.0	0.0	159.0
SO_2	28.2	0.0	0.0	0.0	0.0	0.0	28.2
VOC	68.0	0.0	0.0	0.0	0.0	0.0	68.0
H_2SO_4	43.2	0.0	0.0	0.0	0.0	0.0	43.2
Lead	0.00	0.0	0.0	0.0	0.0	0.0	0.00
CO_2	2,169,524	0.0	0.0	0.0	0.0	0.0	2,169,524
N_2O	1,329	0.0	0.0	0.0	0.0	0.0	1,329
CH_4	1,115	0.0	0.0	0.0	0.0	0.0	1,115
CO_2e (sum)	2,593,514	0.0	0.0	0.0	0.0	0.0	2,593,514

Scenario 2	Hours
DB NG	7,235
NG	0
NG SSSD	1525
DB FO	0
FO	0
FO SUSD	0
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	121.0	0.0	108.3	0.0	0.0	0.0	229.3
CO	55.3	0.0	1,369.0	0.0	0.0	0.0	1,424.2
$PM/PM_{10}/PM_{2.5}$	131.4	0.0	16.6	0.0	0.0	0.0	148.0
SO_2	23.3	0.0	3.9	0.0	0.0	0.0	27.2
VOC	56.1	0.0	117.8	0.0	0.0	0.0	173.9
H_2SO_4	35.7	0.0	6.0	0.0	0.0	0.0	41.6
Lead	0.00	0.0	0.00	0.0	0.0	0.0	0.00
CO_2	1,791,838	0.0	299,651	0.0	0.0	0.0	2,091,490
N_2O	1,098	0.0	184	0.0	0.0	0.0	1,281
CH_4	921	0.0	154	0.0	0.0	0.0	1,075
CO_2e (sum)	2,142,018	0.0	358,212	0.0	0.0	0.0	2,500,230

Scenario 3	Hours
DB NG	6,735
NG	0
NG SSSD	1525
DB FO	0
FO	395
FO SUSD	105
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	112.7	0.0	108.3	0.0	10.2	20.3	251.4
CO	51.4	0.0	1,369.0	0.0	1.5	568.5	1,990.5
$PM/PM_{10}/PM_{2.5}$	122.3	0.0	16.6	0.0	7.8	2.1	148.8
SO_2	21.7	0.0	3.9	0.0	0.9	0.2	26.7
VOC	52.3	0.0	117.8	0.0	0.4	64.5	234.9
H_2SO_4	33.2	0.0	6.0	0.0	1.4	0.4	40.9
Lead	0.00	0.0	0.00	0.0	0.01	0.00	0.01
CO_2	1,668,007	0.0	299,651	0.0	89,392	23,763	2,080,813
N_2O	1,022	0.0	184	0.0	235	63	1,503
CH_4	857	0.0	154	0.0	99	26	1,136
CO_2e (sum)	1,993,986	0.0	358,212	0.0	161,943	43,048	2,557,190

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine Emissions

Scenario 4	Hours
DB NG	0
NG	7,235
NG SSSD	1,525
DB FO	0
FO	0
FO SUSD	0
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	0.0	96.0	108.3	0.0	0.0	0.0	204.3
CO	0.0	43.9	1,369.0	0.0	0.0	0.0	1,412.8
$PM/PM_{10}/PM_{2.5}$	0.0	78.9	16.6	0.0	0.0	0.0	95.5
SO_2	0.0	18.5	3.9	0.0	0.0	0.0	22.4
VOC	0.0	10.0	117.8	0.0	0.0	0.0	127.8
H_2SO_4	0.0	28.3	6.0	0.0	0.0	0.0	34.3
Lead	0.0	0.0	0.0	0.0	0.0	0.0	0.00
CO_2	0.0	1,421,625	299,651	0.0	0.0	0.0	1,721,276
N_2O	0.0	871.0	183.6	0.0	0.0	0.0	1,055
CH_4	0.0	730.7	154.0	0.0	0.0	0.0	885
CO_2e (sum)	0.0	1,699,454	358,212	0.0	0.0	0.0	2,057,666

Scenario 5	Hours
DB NG	0
NG	6,735
NG SSSD	1,525
DB FO	0
FO	395
FO SUSD	105
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	0.0	89.4	108.3	0.0	10.2	20.3	228.2
CO	0.0	40.8	1,369.0	0.0	1.5	568.5	1,979.9
$PM/PM_{10}/PM_{2.5}$	0.0	73.4	16.6	0.0	7.8	2.1	99.9
SO_2	0.0	17.2	3.9	0.0	0.9	0.2	22.2
VOC	0.0	9.4	117.8	0.0	0.4	64.5	192.0
H_2SO_4	0.0	26.3	6.0	0.0	1.4	0.4	34.1
Lead	0.0	0.00	0.00	0.0	0.01	0.00	0.01
CO_2	0.0	1,323,379	299,651	0.0	89,392	23,763	1,736,185
N_2O	0.0	811	184	0.0	235	63	1,292
CH_4	0.0	680	154	0.0	99	26	959
CO_2e (sum)	0.0	1,582,007	358,212	0.0	161,943	43,048	2,145,210

Scenario 6	Hours
DB NG	8,260
NG	0
NG SSSD	0
DB FO	395
FO	0
FO SUSD	105
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	138.2	0.0	0.0	14.4	0.0	20.3	172.9
CO	63.1	0.0	0.0	2.2	0.0	568.5	633.8
$PM/PM_{10}/PM_{2.5}$	150.0	0.0	0.0	10.8	0.0	2.1	162.8
SO_2	26.6	0.0	0.0	1.2	0.0	0.2	28.0
VOC	64.1	0.0	0.0	2.8	0.0	64.5	131.4
H_2SO_4	40.7	0.0	0.0	1.8	0.0	0.4	42.9
Lead	0.00	0.0	0.0	0.01	0.0	0.00	0.01
CO_2	2,045,693	0.0	0.0	110,524	0.0	23762.5	2,179,979
N_2O	1253.4	0.0	0.0	248.1	0.0	62.5	1,564
CH_4	1051.5	0.0	0.0	109.5	0.0	26.2	1,187
CO_2e (sum)	2,445,483	0.0	0.0	187,200	0.0	43048.1	2,675,731

Scenario 7	Hours
DB NG	6,735
NG	0
NG SSSD	1,525
DB FO	395
FO	0
FO SUSD	105
Total Hours	8,760

Pollutant	DB NG	NG	NG SSSD	DB FO	FO	FO SUSD	SUM
	tpy	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	112.7	0.0	108.3	14.4	0.0	20.3	255.6
CO	51.4	0.0	1,369.0	2.2	0.0	568.5	1,991.1
$PM/PM_{10}/PM_{2.5}$	122.3	0.0	16.6	10.8	0.0	2.1	151.7
SO_2	21.7	0.0	3.9	1.2	0.0	0.2	27.0
VOC	52.3	0.0	117.8	2.8	0.0	64.5	237.3
H_2SO_4	33.2	0.0	6.0	1.8	0.0	0.4	41.4
Lead	0.00	0.0	0.00	0.01	0.0	0.00	0.01
CO_2	1,668,007	0.0	299,651	110,524	0.0	23,763	2,101,945
N_2O	1,022	0.0	184	248	0.0	63	1,516
CH_4	857	0.0	154	110	0.0	26	1,147
CO_2e (sum)	1,993,986	0.0	358,212	187,200	0.0	43,048	2,582,446

BURNS McDONNELL

Client NTEC
Project 1x1 Combined Cycle

Combined Cycle Startup Emissions Estimate (Natural Gas)
1x1 8000H Configuration

Rev: 0
Date: 4/18/2018

Startup Emissions per Gas Turbine

	CO	NOx	VOC
	lb/Start	lb/Start	lb/Start
Cold Start	11,066	335	950
Warm Start	6,495	233	558
Hot Start	779	111	67
Shutdown	463	59	40

Startup Times (No Margin)

	Time to Emissions Compliance	Time to Full Load
	Minutes	
Cold Start	105	170
Warm Start	70	113
Hot Start	29	72
Shutdown	25	31

Max Hourly Startup Emissions per Turbine

	CO	NOx	VOC
	lb/hr	lb/hr	lb/hr
Cold Start	7,190	200	620
Warm Start	6,480	210	560
Hot Start	1,200	170	100
Shutdown	3,920	210	340

Startup Times (With Margin)

	Time to Emissions Compliance	Time to Full Load
	Minutes	
Cold Start	120	210
Warm Start	80	130
Hot Start	45	90
Shutdown	30	35

Notes

1) Startup period is defined as the operation period beginning when continuous fuel flow to the gas turbine is initiated and ending when stack emissions compliance is achieved.

2) Maximum lb/hr values are based on the maximum lbs of emission over a rolling hour through out the start up period.

3) Startup emissions estimates assume there is no removal from the catalysts

4) Start Times to emissions compliance start at gas turbine ignition and end when stack emissions compliance is achieved.

5) Start Times to full load start at gas turbine start command and end when gas turbine is at full load, steam turbine is valves wide open, and Bypass valves are closed.

6) Shutdown Times are from gas turbine minimum emissions compliance load (MECL) or gas turbine Full load to flameout.

BURNS McDONNELL

Client NTEC
Project 1x1 Combined Cycle

Combined Cycle Startup Emissions Estimate (Fuel Oil)
1x1 8000H Configuration

Rev: 0
Date: 4/18/2018

Startup Emissions per Gas Turbine

	CO	NOx	VOC
	lb/Start	lb/Start	lb/Start
Cold Start	25,846	860	2,951
Warm Start	12,364	618	1,405
Hot Start	1,854	326	192
Shutdown	1,227	108	122

Startup Times (No Margin)

	Time to Emissions Compliance	Time to Full Load
	Minutes	
Cold Start	105	170
Warm Start	70	113
Hot Start	29	72
Shutdown	25	31

Max Hourly Startup Emissions per Turbine

	CO	NOx	VOC
	lb/hr	lb/hr	lb/hr
Cold Start	16,860	510	1,930
Warm Start	12,140	530	1,390
Hot Start	2,850	500	300
Shutdown	10,440	580	1,040

Startup Times (With Margin)

	Time to Emissions Compliance	Time to Full Load
	Minutes	
Cold Start	120	210
Warm Start	80	130
Hot Start	45	90
Shutdown	30	35

Notes

1) Startup period is defined as the operation period beginning when continuous fuel flow to the gas turbine is initiated and ending when stack emissions compliance is achieved.

2) Maximum lb/hr values are based on the maximum lbs of emission over a rolling hour through out the start up period.

3) Startup emissions estimates assume there is no removal from the catalysts

4) Start Times to emissions compliance start at gas turbine ignition and end when stack emissions compliance is achieved.

5) Start Times to full load start at gas turbine start command and end when gas turbine is at full load, steam turbine is valves wide open, and Bypass valves are closed.

6) Shutdown Times are from gas turbine minimum emissions compliance load (MECL) or gas turbine Full load to flameout.

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine

Case #		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Case Description		Fired Evap OFF Minimum Ambient 1x100% GTG	Fired Evap OFF Winter Peak Ambient 1x100% GTG	Fired Evap OFF Winter Average Ambient 1x100% GTG	Fired Evap OFF Annual Average Ambient 1x100% GTG	Fired Evap ON Summer Average Ambient 1x100% GTG	Fired Evap ON Summer Peak Ambient 1x100% GTG	Fired Evap ON Maximum Ambient 1x100% GTG	Unfired Evap OFF Minimum Ambient 1x100% GTG	Unfired Evap OFF Winter Peak Ambient 1x100% GTG	Unfired Evap OFF Winter Average Ambient 1x100% GTG	Unfired Evap OFF Annual Average Ambient 1x100% GTG	Unfired Evap ON Summer Average Ambient 1x100% GTG	Unfired Evap ON Summer Peak Ambient 1x100% GTG	Unfired Evap ON Maximum Ambient 1x100% GTG	Unfired Evap OFF Minimum Ambient 1x75% GTG	Unfired Evap OFF Winter Peak Ambient 1x75% GTG	Unfired Evap OFF Winter Average Ambient 1x75% GTG	Unfired Evap OFF Annual Average Ambient 1x75% GTG	Unfired Evap OFF Summer Average Ambient 1x75% GTG	Unfired Evap OFF Summer Peak Ambient 1x75% GTG	Unfired Evap Max Ambient 1x75% GTG
Ambient Temperature		-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F	-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F	-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F
Gas Turbine Load		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	75%	75%	75%	75%	75%	75%	75%
Evaporative Cooling		OFF	OFF	OFF	OFF	COOLING ON	COOLING ON	COOLING ON	OFF	OFF	OFF	OFF	COOLING ON	COOLING ON	COOLING ON	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Firing		FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Inlet Chiller		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
No. of Gas Turbines In Operation		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Duct Burner Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions																						
Temperature	degree F	-34.3	7.9	15.4	39.1	61	76.8	95.5	-34.3	7.9	15.4	39.1	61	76.8	95.5	-34.3	7.9	15.4	39.1	61	76.8	95.5
Relative Humidity	%	70%	69%	70%	70%	76%	62%	36%	70%	69%	70%	70%	76%	62%	36%	70%	69%	70%	70%	76%	62%	36%
Wet Bulb Temperature	degree F	-34.5	6.5	13.5	35.4	56.4	67.3	73.6	-34.5	6.5	13.5	35.4	56.4	67.3	73.6	-34.5	6.5	13.5	35.4	56.4	67.3	73.6
Pressure	psia	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Gas Turbine Generator Performance																						
Electrical Output	kW	305,185	321,687	318,848	308,281	299,825	290,408	284,119	305,185	321,687	318,848	308,281	299,825	290,408	284,119	228,890	241,193	239,136	231,211	222,417	211,956	196,065
Heat Rate - LHV	Btu/kWh	10,583	10,270	10,241	10,220	10,216	10,285	10,307	10,583	10,270	10,241	10,220	10,216	10,285	10,307	11,029	10,606	10,607	10,633	10,694	10,802	11,051
Heat Rate - HHV	Btu/kWh	11,740	11,393	11,361	11,338	11,333	11,410	11,434	11,740	11,393	11,361	11,338	11,333	11,410	11,434	12,235	11,766	11,767	11,796	11,864	11,984	12,259
GTG Heat Input- LHV	MMBtu/hr	3,230	3,304	3,265	3,151	3,063	2,987	2,928	3,230	3,304	3,265	3,151	3,063	2,987	2,928	2,524	2,558	2,536	2,459	2,379	2,290	2,167
GTG Heat Input- HHV	MMBtu/hr	3,583	3,665	3,622	3,495	3,398	3,314	3,249	3,583	3,665	3,622	3,495	3,398	3,314	3,249	2,801	2,838	2,814	2,727	2,639	2,540	2,404
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	6,341,490	6,495,270	6,440,176	6,268,714	6,106,456	5,964,540	5,857,095	6,341,490	6,495,270	6,440,176	6,268,714	6,106,456	5,964,540	5,857,096	5,046,885	5,102,834	5,086,122	5,000,930	4,898,065	4,772,174	4,543,438
Exhaust Temperature	degree F	1,184	1,195	1,195	1,202	1,208	1,217	1,220	1,184	1,195	1,195	1,202	1,208	1,217	1,220	1,192	1,202	1,202	1,205	1,210	1,214	1,225
Steam Turbine Generator Performance																						
Electrical Output	kW	254,623	255,309	255,183	255,424	254,270	252,656	247,917	158,036	164,309	162,993	160,825	157,486	154,524	151,354	127,005	130,306	129,736	128,215	125,965	121,942	115,982
Duct Burner Fuel Consumption																						
Heat Input, LHV (per HRSG)	MMBtu/hr	907.1	860.3	870.1	887.9	896.3	898.5	882.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	1006.3	954.4	965.2	985.0	994.3	996.8	978.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet																						
Ar	%	0.88%	0.88%	0.88%	0.88%	0.87%	0.86%	0.86%	0.89%	0.89%	0.89%	0.89%	0.88%	0.87%	0.87%	0.89%	0.89%	0.89%	0.89%	0.88%	0.88%	0.87%
CO2	%	5.42%	5.33%	5.34%	5.35%	5.36%	5.37%	5.35%	4.29%	4.28%	4.27%	4.23%	4.20%	4.19%	4.17%	4.22%	4.22%	4.20%	4.14%	4.07%	4.02%	3.99%
H2O	%	10.51%	10.45%	10.52%	10.90%	11.85%	12.54%	12.97%	8.31%	8.41%	8.44%	8.72%	9.61%	10.26%	10.71%	8.16%	8.29%	8.31%	8.55%	9.23%	9.66%	9.72%
N2	%	73.93%	73.91%	73.86%	73.57%	72.84%	72.30%	71.95%	74.80%	74.71%	74.68%	74.43%	73.71%	73.19%	72.84%	74.86%	74.76%	74.73%	74.49%	73.91%	73.54%	73.47%
O2	%	9.22%	9.39%	9.36%	9.27%	9.05%	8.88%	8.82%	11.68%	11.67%	11.69%	11.70%	11.56%	11.45%	11.39%	11.84%	11.80%	11.84%	11.90%	11.87%	11.87%	11.91%
Stack Emissions at Exit																						
NOx Emissions																						
NOx,@15% O2 Into SCR	ppmvd	33.4	33.5	33.4	33.4	33.3	33.3	33.3	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	554.9	560.1	555.8	541.6	530.2	519.8	509.7	454.2	464.6	459.2	443.1	430.8	420.1	411.9	355.0	359.8	356.7	345.8	334.5	322.0	304.7
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	33.2	33.5	33.2	32.5	31.8	31.2	30.6	26.0	26.5	26.2	25.3	24.6	24.0	23.5	20.3	20.6	20.4	19.8	19.1	18.4	17.4
SCR NOx Removal Efficiency	%	94.0%	94.0%	94.0%	94.0%	94.0%	94.0%	94.0%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%
NH3 Emissions																						
NH3 Reacted with NOx (per HRSG)	lb/hr	251.0	253.4	251.5	245.0	239.8	235.1	230.6	206.1	210.8	208.4	201.1	195.5	190.6	186.9	161.1	163.2	161.9	156.9	151.8	146.1	138.3
NH3 slip @ 15% O2	ppmvd	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
NH3 slip (per HRSG)	lb/hr	61.5	61.9	61.5	60.1	58.9	57.8	56.7	48.0	49.1	48.6	46.9	45.6	44.4	43.6	37.6	38.1	37.7	36.6	35.4	34.1	32.2
CO Emissions																						
CO into catalyst	ppmvd	19.8	18.8	19.0	19.7	20.3	20.8	20.9	5.5	5.5	5.5	5.5	5.5	5.5	5.5	13.5	13.6	13.5	13.3	13.2	13.1	13.0
CO into catalyst, @ 15% O2	ppmvd	11.1	10.7	10.8	11.1	11.3	11.5	11.5	4.0	4.0	4.0	4.0	4.0	4.0	4.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
CO into catalyst (per HRSG)	lb/hr	112.1	108.7	109.2	109.6	109.5	109.0	107.0	31.6	32.3	32.0	30.8	30.0	29.2	28.7	61.8	62.6	62.1	60.2	58.2	56.0	53.0
CO out of catalyst	ppmvd	2.69	2.64	2.64	2.66	2.69	2.72	2.73	2.07	2.07	2.06	2.05	2.06	2.06	2.07	2.03	2.04	2.03	2.00	1.99	1.97	1.96
CO out of catalyst, @ 15% O2	ppmvd	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
CO out of catalyst (per HRSG)	lb/hr	15.2	15.3	15.2	14.8	14.5	14.3	14.0	11.9	12.1	12.0	11.6	11.2	11.0	10.7	9.3	9.4	9.3	9.0	8.7	8.4	8.0
CO Catalyst Removal Efficiency	%	86.5%	85.9%	86.1%	86.5%	86.7%	86.9%	86.9%	62.5%	62.5%	62.5%	62.5%	62.5%	62.5%	62.5%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
SO2 Emissions																						
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.247	0.248	0.247	0.246	0.244	0.242	0.241	0.253	0.253	0.253	0.252	0.250	0.248	0.247	0.254	0.253	0.253	0.253	0.251	0.250	0.249
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276	0.276
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	6.4	6.4	6.4	6.2	6.1	6.0	5.9	5.0	5.1	5.0	4.9	4.7	4.6	4.5	3.9	4.0	3.9	3.8	3.7	3.5	3.4
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139
Volatile Organic Compounds																						
VOC @ 15% O2	ppmvd	2.7	2.7	2.7	2.7	2.7	2.7	2.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
VOC as CH4 (per HRSG)	lb/hr	15.4	15.5	15.4	15.0	14.8	14.5	14.2	2.7	2.8	2.7	2.6	2.6	2.5	2.5	2.1	2.2	2.1	2.1	2.0	1.9	1.8
VOC % Removal in Catalyst	%	37%	35%	35%	38%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Particulates																						
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	28.8	28.5	28.4	28.2	27.8	27.5	26.9	15.8	16.2	16.0	15.5	15.0	14.6	14.3	12.4	12.5	12.4	12.2	11.9	11.6	11.2
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	36.3	36.0	36.0	35.6	35.1	34.6	33.9	21.3	21.8	21.6	20.9	20.3	19.7	19.3	16.7	16.8	16.7	16.5	16.2	16.0	15.6
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00791	0.00780	0.00784	0.00794	0.00799	0.00803	0.00803	0.00595	0.00595	0.00596	0.00598	0.00597	0.00596	0.00595	0.00596	0.00592	0.00595	0.00605	0.00615	0.00628	0.00647
H2SO4 Emissions																						
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	9.79	9.86	9.79	9.56	9.37	9.20	9.02	7.65	7.82	7.73	7.46	7.25	7.07	6.93	5.98	6.06	6.01	5.82	5.63	5.42	5.13
H2SO4 in Exhaust Gas	lb/MMBtu	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213
GHG Emissions																						
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	492,096	495,325	491,927	480,427	470,968	462,194	453,310	384,196	392,985	388,425	374,804	364,352	355,313	348,348	300,304	304,291	301,730	292,457	282,953	272,368	257,741
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	879.0	858.5	857.0	852.3	850.0	851.1	852.0	829.4	808.6	806.1	799.0	796.7	798.6	799.9	843.8	819.1	818.0	813.7	812.2	815.7	826.0
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02
CH4 in Exhaust Gas (per HRSG)	lb/hr	252.9	254.6	252.8	246.9	242.1	237.6	233.0	197.5	202.0	199.6	192.6	187.3	182.6	179.1	154.4	156.4	155.1	150.3	145.4	140.0	132.5
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02
N2O in Exhaust Gas (per HRSG)	lb/hr	301.5	303.5	301.4	294.4	288.6	283.2	277.7	235.4	240.8	238.0	229.6	223.2	217.7	213.4	184.0	186.4	184.9	179.2	173.4	166.9	157.9
GHG in Exhaust Gas (per HRSG)	lb/hr	492,650.7	495,883.1	492,480.8	480,967.9	471,498.8	462,715.1	453,820.2	384,629.3	393,428.3	388,862.6	375,226.2	364,762.5	355,713.3	348,740.7	300,642.0	304,634.1	302,070.4	292,786.6	283,271.5	272,674.5	258,031.2
Stack Exit																						
Temperature	degree F	164	164	164	165	165	165	165	167	168	167	167	169	170	171	165	165	165	165	165	165	165
Flow Rate (per HRSG)	lb/hr	6,385,420	6,536,937	6,482,315	6,311,717	6,149,863	6,008,056	5,899,829	6,341,490	6,495,270	6,440,176	6,268,714	6,106,456	5,964,540	5,857,096	5,046,885	5,102,834	5,086,122	5,000,930	4,898,065	4,772,174	4,543,438
Flow Rate (per HRSG)	scfm	1,187,865	1,216,129	1,206,283	1,176,216	1,150,232	1,126,707	1,108,344	1,174,082	1,203,057	1,193,062	1,162,725	1,136,614	1,113,056	1,094,939	934,102	944,911	941,950	927,225	910,735	888,969	846,630
Flow Rate (per HRSG)	acfm	1,460,169	1,496,266	1,484,101	1,449,619	1,416,832	1,388,416	1,365,742	1,451,496	1,488,999	1,475,747	1,437,799	1,409,239	1,382,539	1,361,747	1,151,028	1,164,375	1,160,709	1,142,353	1,122,002	1,095,221	1,043,011
Stack Velocity	ft/sec	68.4	70.1	69.5	67.9	66.4	65.1	64.0	68.0	69.8	69.2	67.4	66.0	64.8	63.8	53.9	54.6	54.4	53.5	52.6	51.3	48.9
Stack Diameter	ft	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3

Notes:
1. Particulate values exclude catalyst and other entrained particles.
2. Emission values do not include heavy metals (lead, mercury, etc.)
3. Differing fuel composition may change the calculated emissions.
4. CTG performance based on performance runs provided by SEI.
5. Fuel based on natural gas analysis provided by NTEC.
6. 35 ppm NOx control on 8000H gas turbine.
8. Stack SO2 content reported with no conversion to SO3.
9. Particulate emissions assume 100% conversion of SO2-SO3, and 100% coversion of SO3 to (NH4)2SO4.
10. H2SO4 assumes 100% conversion of SO2-SO3, and 100% conversion of SO3 to H2SO4.
11. Greenhouse Gas (GHG) emissions are based on EPA 40 CFR Part 98 emissions factors for natural gas.
12. 20% margin in Fuel flow and 20% margin in exhaust flow are included.
13. Emissions reported on the basis of pounds per hour are for one combustion turbine and one HRSG.
14. Emissions estimates are for information only and are NOT guaranteed.

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine

Case #		29	30	31	32	33	34	35
Case Description		Unfired Evap OFF Minimum Ambient 1xMECL GTG	Unfired Evap OFF Winter Peak Ambient 1xMECL GTG	Unfired Evap OFF Average Ambient 1xMECL GTG	Unfired Evap OFF Annual Average Ambient 1xMECL GTG	Unfired Evap OFF Summer Average Ambient 1xMECL GTG	Unfired Evap OFF Summer Peak Ambient 1xMECL GTG	Unfired Evap OFF Maximum Ambient 1xMECL GTG
Ambient Temperature		-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F
Gas Turbine Load		34%	33%	33%	34%	35%	36%	37%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Firing		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Inlet Chiller		OFF	OFF	OFF	OFF	OFF	OFF	OFF
No. of Gas Turbines In Operation		1	1	1	1	1	1	1
Gas Turbine Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Duct Burner Fuel		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions								
Temperature	degree F	-34.3	7.9	15.4	39.1	61	76.8	95.5
Relative Humidity	%	70%	69%	70%	70%	76%	62%	36%
Wet Bulb Temperature	degree F	-34.5	6.5	13.5	35.4	56.4	67.3	73.6
Pressure	psia	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Gas Turbine Generator Performance								
Electrical Output	kW	104,700	104,700	104,732	104,700	104,700	104,700	104,700
Heat Rate - LHV	Btu/kWh	14,789	14,356	14,302	14,148	14,030	13,946	13,898
Heat Rate - HHV	Btu/kWh	16,406	15,926	15,866	15,695	15,565	15,472	15,418
GTG Heat Input- LHV	MMBtu/hr	1,548	1,503	1,498	1,481	1,469	1,460	1,455
GTG Heat Input- HHV	MMBtu/hr	1,718	1,667	1,662	1,643	1,630	1,620	1,614
Water / Sprint Injection Rate (per HRSG)	lb/hr	0	0	0	0	0	0	0
Exhaust Flow (per HRSG)	lb/hr	3,526,941	3,452,470	3,452,088	3,454,351	3,454,625	3,456,818	3,444,104
Exhaust Temperature	degree F	1,202	1,210	1,210	1,210	1,210	1,210	1,210
Steam Turbine Generator Performance								
Electrical Output	kW	86,643	84,982	85,488	85,946	86,527	85,303	83,931
Duct Burner Fuel Consumption								
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet								
Ar	%	0.90%	0.89%	0.89%	0.89%	0.88%	0.88%	0.88%
CO2	%	3.71%	3.68%	3.67%	3.62%	3.58%	3.55%	3.55%
H2O	%	7.18%	7.24%	7.27%	7.55%	8.27%	8.76%	8.87%
N2	%	75.25%	75.18%	75.14%	74.89%	74.29%	73.89%	73.81%
O2	%	12.94%	12.98%	13.00%	13.02%	12.94%	12.89%	12.87%
Stack Emissions at Exit								
NOx Emissions								
NOx,@15% O2 Into SCR	ppmvd	35.0	35.0	35.0	35.0	35.0	35.0	35.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	217.8	211.4	210.7	208.3	206.6	205.4	204.7
NOx,@15% O2 Out of SCR	ppmvd	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	12.4	12.1	12.0	11.9	11.8	11.7	11.7
SCR NOx Removal Efficiency	%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%
NH3 Emissions								
NH3 Reacted with NOx (per HRSG)	lb/hr	98.8	95.9	95.6	94.5	93.7	93.2	92.9
NH3 slip @ 15% O2	ppmvd	10	10	10	10	10	10	10
NH3 slip (per HRSG)	lb/hr	23.0	22.4	22.3	22.0	21.9	21.7	21.6
CO Emissions								
CO into catalyst	ppmvd	11.8	11.7	11.7	11.5	11.5	11.5	11.5
CO into catalyst, @ 15% O2	ppmvd	10.0	10.0	10.0	10.0	10.0	10.0	10.0
CO into catalyst (per HRSG)	lb/hr	37.9	36.8	36.6	36.2	35.9	35.7	35.6
CO out of catalyst	ppmvd	1.77	1.75	1.75	1.73	1.72	1.72	1.72
CO out of catalyst, @ 15% O2	ppmvd	1.50	1.50	1.50	1.50	1.50	1.50	1.50
CO out of catalyst (per HRSG)	lb/hr	5.7	5.5	5.5	5.4	5.4	5.4	5.3
CO Catalyst Removal Efficiency	%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
SO2 Emissions								
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.257	0.256	0.256	0.255	0.253	0.252	0.252
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.276	0.276	0.276	0.276	0.276	0.276	0.276
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	2.4	2.3	2.3	2.3	2.3	2.3	2.3
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139	0.00139
Volatile Organic Compounds								
VOC @ 15% O2	ppmvd	0.6	0.6	0.6	0.6	0.6	0.6	0.6
VOC as CH4 (per HRSG)	lb/hr	1.3	1.3	1.3	1.2	1.2	1.2	1.2
VOC % Removal in Catalyst	%	40%	40%	40%	40%	40%	40%	40%
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	8.9	8.8	8.8	8.7	8.7	8.7	8.6
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	12.9	12.8	12.8	12.7	12.7	12.7	12.6
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.00753	0.00767	0.00769	0.00774	0.00778	0.00781	0.00783
H2SO4 Emissions								
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	3.67	3.56	3.55	3.51	3.48	3.46	3.45
H2SO4 in Exhaust Gas	lb/MMBtu	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213	0.00213
GHG Emissions								
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98
CO2 in Exhaust Gas (per HRSG)	lb/hr	184,191	178,796	178,178	176,210	174,746	173,699	173,102
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	962.6	942.6	936.7	924.3	913.8	914.2	917.7
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02	5.5116E-02
CH4 in Exhaust Gas (per HRSG)	lb/hr	94.7	91.9	91.6	90.6	89.8	89.3	89.0
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02	6.5698E-02
N2O in Exhaust Gas (per HRSG)	lb/hr	112.9	109.5	109.2	108.0	107.1	106.4	106.1
GHG in Exhaust Gas (per HRSG)	lb/hr	184,398.8	178,997.4	178,378.5	176,408.8	174,942.5	173,895.1	173,296.6
Stack Exit								
Temperature	degree F	165	165	165	165	165	165	165
Flow Rate (per HRSG)	lb/hr	3,526,941	3,452,470	3,452,088	3,454,351	3,454,625	3,456,818	3,444,104
Flow Rate (per HRSG)	scfm	651,405	637,853	637,899	639,092	641,022	642,689	640,596
Flow Rate (per HRSG)	acfm	802,569	785,817	785,881	787,333	789,733	791,777	789,189
Stack Velocity	ft/sec	37.6	36.8	36.8	36.9	37.0	37.1	37.0
Stack Diameter	ft	21.3	21.3	21.3	21.3	21.3	21.3	21.3

Case #		36	37	38	39	40	41	42
Case Description		Fired NG CTG Fuel Oil Evap OFF Min Ambient 1x100% CTG	Fired NG CTG Fuel Oil Evap OFF Winter Peak 1x100% CTG	Fired NG CTG Fuel Oil Evap OFF Winter Average 1x100% CTG	Fired NG CTG Fuel Oil Evap OFF Annual Average 1x100% CTG	Fired NG CTG Fuel Oil Evap ON Summer Average 1x100% CTG	Fired NG CTG Fuel Oil Evap ON Summer Peak 1x100% CTG	Fired NG CTG Fuel Oil Evap ON Maximum Ambient 1x100% CTG
Ambient Temperature		-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F
Gas Turbine Load		100%	100%	100%	100%	100%	100%	100%
Evaporative Cooling		OFF	OFF	OFF	OFF	COOLING ON	COOLING ON	COOLING ON
Water Injection		INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON	FIRING ON
Inlet Chiller		OFF	OFF	OFF	OFF	OFF	OFF	OFF
No. of Gas Turbines In Operation		1	1	1	1	1	1	1
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Duct Burner Fuel		Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1	Natural Gas 1
Ambient Conditions								
Temperature	degree F	-34.3	7.9	15.4	39.1	61	76.8	95.5
Relative Humidity	%	70%	69%	70%	70%	76%	62%	36%
Wet Bulb Temperature	degree F	-34.5	6.5	13.5	35.4	56.4	67.3	73.6
Pressure	psia	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Gas Turbine Generator Performance								
Electrical Output	kW	238,275	258,677	258,311	258,880	260,519	261,332	255,498
Heat Rate - LHV	Btu/kWh	11,341	10,807	10,776	10,733	10,732	10,764	10,826
Heat Rate - HHV	Btu/kWh	12,180	11,606	11,573	11,526	11,525	11,560	11,627
GTG Heat Input- LHV	MMBtu/hr	2,702	2,796	2,784	2,779	2,796	2,813	2,766
GTG Heat Input- HHV	MMBtu/hr	2,902	3,002	2,989	2,984	3,002	3,021	2,971
Water / Sprint Injection Rate (per HRSG)	lb/hr	46,871	54,548	55,823	69,275	78,798	85,376	86,959
Exhaust Flow (per HRSG)	lb/hr	6,374,610	6,542,912	6,490,652	6,339,790	6,194,311	6,064,364	5,960,302
Exhaust Temperature	degree F	1,001	1,012	1,020	1,046	1,076	1,104	1,109
Steam Turbine Generator Performance								
Electrical Output	kW	211,873	212,141	214,219	219,919	227,467	230,308	225,980
Duct Burner Fuel Consumption								
Heat Input, LHV (per HRSG)	MMBtu/hr	907.2	860.3	870.1	887.9	896.3	898.5	882.3
Heat Input, HHV (per HRSG)	MMBtu/hr	1006.4	954.4	965.2	985.0	994.3	996.8	978.9
Stack Volumetric Analysis, Wet								
Ar	%	0.87%	0.87%	0.86%	0.86%	0.85%	0.84%	0.83%
CO2	%	5.77%	5.72%	5.75%	5.88%	6.03%	6.17%	6.15%
H2O	%	8.00%	8.13%	8.28%	9.16%	10.49%	11.50%	12.01%
N2	%	72.90%	72.74%	72.63%	71.98%	70.97%	70.20%	69.80%
O2	%	12.42%	12.51%	12.43%	12.08%	11.62%	11.25%	11.16%
Stack Emissions at Exit								
NOx Emissions								
NOx,@15% O2 Into SCR	ppmvd	37.9	38.1	38.1	38.0	38.0	38.0	38.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	448.1	454.8	454.3	455.4	458.3	460.6	452.7
NOx,@15% O2 Out of SCR	ppmvd	6.0	6.0	6.0	6.0	6.0	6.0	6.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	71.0	71.6	71.6	71.9	72.4	72.7	71.4
SCR NOx Removal Efficiency	%	84.2%	84.3%	84.2%	84.2%	84.2%	84.2%	84.2%
NH3 Emissions								
NH3 Reacted with NOx (per HRSG)	lb/hr	181.5	184.4	184.2	184.6	185.7	186.7	183.5
NH3 slip @ 15% O2	ppmvd	10	10	10	10	10	10	10
NH3 slip (per HRSG)	lb/hr	43.8	44.2	44.2	44.4	44.6	44.8	44.1
CO Emissions								
CO into catalyst	ppmvd	22.7	21.8	22.1	23.0	24.0	24.8	24.9
CO into catalyst, @ 15% O2	ppmvd	18.2	17.7	17.8	17.9	17.9	17.9	17.9
CO into catalyst (per HRSG)	lb/hr	130.9	128.4	129.1	130.5	131.6	132.1	129.8
CO out of catalyst	ppmvd	1.88	1.85	1.87	1.93	2.01	2.08	2.08
CO out of catalyst, @ 15% O2	ppmvd	1.50	1.50	1.50	1.50	1.50	1.50	1.50
CO out of catalyst (per HRSG)	lb/hr	10.8	10.9	10.9	10.9	11.0	11.1	10.9
CO Catalyst Removal Efficiency	%	91.7%	91.5%	91.6%	91.6%	91.6%	91.6%	91.6%
SO2 Emissions								
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.329	0.330	0.329	0.326	0.322	0.318	0.316
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.358	0.360	0.359	0.359	0.359	0.360	0.360
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	5.9	6.0	6.0	6.0	6.0	6.1	6.0
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00151	0.00151	0.00151	0.00151	0.00151	0.00151	0.00151
Volatile Organic Compounds								
VOC @ 15% O2	ppmvd	3.3	3.3	3.3	3.3	3.3	3.3	3.3
VOC as CH4 (per HRSG)	lb/hr	13.8	13.9	13.9	13.9	14.0	14.1	13.9
VOC % Removal in Catalyst	%	40%	37%	38%	38%	39%	39%	38%
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	37.2	36.9	37.0	37.2	37.4	37.5	37.1
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	54.3	53.8	53.9	54.2	54.4	54.5	54.1
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01389	0.01360	0.01364	0.01366	0.01362	0.01357	0.01369
H2SO4 Emissions								
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	9.03	9.14	9.14	9.17	9.24	9.28	9.13
H2SO4 in Exhaust Gas	lb/MMBtu	0.00231	0.00231	0.00231	0.00231	0.00231	0.00231	0.00231
GHG Emissions								
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.45	163.45	163.45	163.45	163.45	163.45	163.45
CO2 in Exhaust Gas (per HRSG)	lb/hr	542,846	552,266	551,496	552,807	556,581	559,613	550,152
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,205.9	1,173.0	1,167.1	1,154.6	1,140.6	1,138.3	1,142.6
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01
CH4 in Exhaust Gas (per HRSG)	lb/hr	535.3	549.0	547.5	547.7	551.2	554.4	545.1
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01
N2O in Exhaust Gas (per HRSG)	lb/hr	1,210.1	1,246.1	1,241.8	1,240.9	1,248.8	1,256.3	1,235.3
GHG in Exhaust Gas (per HRSG)	lb/hr	544,591.4	554,061.4	553,285.6	554,595.3	558,381.6	561,423.9	551,932.5
Stack Exit								
Temperature	degree F	186	185	185	183	184	177	184
Flow Rate (per HRSG)	lb/hr	6,418,548	6,584,579	6,532,792	6,382,793	6,237,719	6,107,880	6,003,036
Flow Rate (per HRSG)	scfm	1,176,074	1,207,255	1,198,308	1,174,130	1,152,671	1,132,427	1,115,224
Flow Rate (per HRSG)	acfm	1,498,773	1,535,605	1,524,302	1,488,626	1,463,036	1,421,231	1,416,180
Stack Velocity	ft/sec	70.2	72.0	71.4	69.8	68.6	66.6	66.4
Stack Diameter	ft	21.3	21.3	21.3	21.3	21.3	21.3	21.3

Case #		43	44	45	46	47	48	49
Case Description		Unfired Fuel Oil Evap OFF Min Ambient 1x100% CTG	Unfired Fuel Oil Evap OFF Winter Peak 1x100% CTG	Unfired Fuel Oil Evap OFF Winter Average 1x100% CTG	Unfired Fuel Oil Evap OFF Annual Average 1x100% CTG	Unfired Fuel Oil Evap ON Summer Average 1x100% CTG	Unfired Fuel Oil Evap ON Summer Peak 1x100% CTG	Unfired Fuel Oil Evap ON Maximum Ambient 1x100% CTG
Ambient Temperature		-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F
Gas Turbine Load		100%	100%	100%	100%	100%	100%	100%
Evaporative Cooling		OFF	OFF	OFF	OFF	COOLING ON	COOLING ON	COOLING ON
Water Injection		INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		OFF	OFF	OFF	OFF	OFF	OFF	OFF
Inlet Chiller		OFF	OFF	OFF	OFF	OFF	OFF	OFF
No. of Gas Turbines In Operation		1	1	1	1	1	1	1
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Duct Burner Fuel		N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions								
Temperature	degree F	-34.3	7.9	15.4	39.1	61	76.8	95.5
Relative Humidity	%	70%	69%	70%	70%	76%	62%	36%
Wet Bulb Temperature	degree F	-34.5	6.5	13.5	35.4	56.4	67.3	73.6
Pressure	psia	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Gas Turbine Generator Performance								
Electrical Output	kW	238,275	258,677	258,311	258,880	260,519	261,332	255,498
Heat Rate - LHV	Btu/kWh	11,341	10,807	10,776	10,733	10,732	10,764	10,826
Heat Rate - HHV	Btu/kWh	12,180	11,606	11,573	11,526	11,525	11,560	11,627
GTG Heat Input- LHV	MMBtu/hr	2,702	2,796	2,784	2,779	2,796	2,813	2,766
GTG Heat Input- HHV	MMBtu/hr	2,902	3,002	2,989	2,984	3,002	3,021	2,971
Water / Sprint Injection Rate (per HRSG)	lb/hr	46,871	54,548	55,823	69,275	78,798	85,376	86,959
Exhaust Flow (per HRSG)	lb/hr	6,374,610	6,542,912	6,490,652	6,339,790	6,194,311	6,064,364	5,960,302
Exhaust Temperature	degree F	1,001	1,012	1,020	1,046	1,076	1,104	1,109
Steam Turbine Generator Performance								
Electrical Output	kW	115,287	121,141	122,029	125,319	130,683	132,177	129,417
Duct Burner Fuel Consumption								
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet								
Ar	%	0.88%	0.88%	0.87%	0.87%	0.86%	0.85%	0.84%
CO2	%	4.66%	4.69%	4.71%	4.79%	4.91%	5.03%	5.02%
H2O	%	5.79%	6.09%	6.21%	7.01%	8.30%	9.28%	9.80%
N2	%	73.75%	73.52%	73.43%	72.80%	71.80%	71.04%	70.63%
O2	%	14.89%	14.79%	14.75%	14.49%	14.10%	13.77%	13.67%
Stack Emissions at Exit								
NOx Emissions								
NOx,@15% O2 Into SCR	ppmvd	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	347.4	359.3	357.8	356.9	358.9	360.9	354.9
NOx,@15% O2 Out of SCR	ppmvd	6.0	6.0	6.0	6.0	6.0	6.0	6.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	49.6	51.3	51.1	51.0	51.3	51.6	50.7
SCR NOx Removal Efficiency	%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
NH3 Emissions								
NH3 Reacted with NOx (per HRSG)	lb/hr	143.3	148.2	147.6	147.2	148.0	148.9	146.4
NH3 slip @ 15% O2	ppmvd	10	10	10	10	10	10	10
NH3 slip (per HRSG)	lb/hr	30.6	31.7	31.5	31.5	31.6	31.8	31.3
CO Emissions								
CO into catalyst	ppmvd	8.6	8.7	8.8	9.0	9.4	9.7	9.7
CO into catalyst, @ 15% O2	ppmvd	10.0	10.0	10.0	10.0	10.0	10.0	10.0
CO into catalyst (per HRSG)	lb/hr	50.4	52.1	51.9	51.7	52.0	52.3	51.4
CO out of catalyst	ppmvd	1.30	1.31	1.32	1.35	1.41	1.45	1.46
CO out of catalyst, @ 15% O2	ppmvd	1.50	1.50	1.50	1.50	1.50	1.50	1.50
CO out of catalyst (per HRSG)	lb/hr	7.6	7.8	7.8	7.8	7.8	7.8	7.7
CO Catalyst Removal Efficiency	%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
SO2 Emissions								
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.360	0.359	0.358	0.356	0.351	0.347	0.345
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.382	0.382	0.382	0.382	0.383	0.383	0.383
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	4.4	4.6	4.5	4.5	4.6	4.6	4.5
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152
Volatile Organic Compounds								
VOC @ 15% O2	ppmvd	0.6	0.6	0.6	0.6	0.6	0.6	0.6
VOC as CH4 (per HRSG)	lb/hr	1.7	1.8	1.8	1.8	1.8	1.8	1.8
VOC % Removal in Catalyst	%	40%	40%	40%	40%	40%	40%	40%
Particulates								
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	24.1	24.4	24.4	24.3	24.4	24.4	24.3
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	39.1	39.4	39.4	39.3	39.4	39.4	39.3
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01347	0.01312	0.01316	0.01318	0.01312	0.01306	0.01323
H2SO4 Emissions								
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	6.74	6.97	6.94	6.93	6.97	7.01	6.90
H2SO4 in Exhaust Gas	lb/MMBtu	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232
GHG Emissions								
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.45	163.45	163.45	163.45	163.45	163.45	163.45
CO2 in Exhaust Gas (per HRSG)	lb/hr	434,815	449,819	447,886	447,073	449,853	452,619	445,081
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,229.8	1,184.3	1,177.6	1,163.6	1,149.9	1,150.2	1,156.3
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01
CH4 in Exhaust Gas (per HRSG)	lb/hr	479.8	496.4	494.3	493.4	496.4	499.5	491.2
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01
N2O in Exhaust Gas (per HRSG)	lb/hr	1,144.0	1,183.4	1,178.3	1,176.2	1,183.5	1,190.8	1,171.0
GHG in Exhaust Gas (per HRSG)	lb/hr	436,438.8	451,499.0	449,558.6	448,742.6	451,533.3	454,309.8	446,742.6
Stack Exit								
Temperature	degree F	186	185	185	183	184	177	184
Flow Rate (per HRSG)	lb/hr	6,374,610	6,542,912	6,490,652	6,339,790	6,194,311	6,064,364	5,960,302
Flow Rate (per HRSG)	scfm	1,162,424	1,194,312	1,185,218	1,160,775	1,139,195	1,118,921	1,101,960
Flow Rate (per HRSG)	acfm	1,481,377	1,519,142	1,507,651	1,471,694	1,445,931	1,404,280	1,399,337
Stack Velocity	ft/sec	69.4	71.2	70.7	69.0	67.8	65.8	65.6
Stack Diameter	ft	21.3	21.3	21.3	21.3	21.3	21.3	21.3

Notes:
1. Particulate values exclude catalyst and other entrained particles.
2. Emission values do not include heavy metals (lead, mercury, etc.)
3. Differing fuel composition may change the calculated emissions.
4. CTG performance based on performance runs provided by SEI.
5. Fuel based on natural gas analysis provided by NTEC.
6. 35 ppm NOx control on 8000H gas turbine.
8. Stack SO2 content reported with no conversion to SO3.
9. Particulate emissions assume 100% conversion of SO2-SO3, and 100% cove
10. H2SO4 assumes 100% conversion of SO2-SO3, and 100% conversion of SO
11. Greenhouse Gas (GHG) emissions are based on EPA 40 CFR Part 98 emissi
12. 20% margin in Fuel flow and 20% margin in exhaust flow are included.
13. Emissions reported on the basis of pounds per hour are for one combustion tu
14. Emissions estimates are for information only and are NOT guaranteed.

South Shore Energy, LLC - Nemadji Trail Energy Center
Combustion Turbine

Case #		50	51	52	53	54	55	56	62	63
Case Description		Unfired Fuel Oil Evap OFF Min Ambient 1x75% CTG	Unfired Fuel Oil Evap OFF Winter Peak 1x75% CTG	Unfired Fuel Oil Evap OFF Winter Average 1x75% CTG	Unfired Fuel Oil Evap OFF Annual Average 1x75% CTG	Unfired Fuel Oil Evap OFF Summer Average 1x75% CTG	Unfired Fuel Oil Evap OFF Summer Peak 1x75% CTG	Unfired Fuel Oil Evap OFF Maximum Ambient 1x75% CTG	Unfired Fuel Oil Evap OFF Summer Peak 1xMECL CTG	Unfired Fuel Oil Evap OFF Maximum Ambient 1xMECL CTG
Ambient Temperature		-34.3 F	7.9 F	15.4 F	39.1 F	61 F	76.8 F	95.5 F	76.8 F	95.5 F
Gas Turbine Load		75%	75%	75%	75%	75%	75%	75%	49%	46%
Evaporative Cooling		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Water Injection		INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON	INJECTION ON
Duct Firing		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Inlet Chiller		OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
No. of Gas Turbines In Operation		1	1	1	1	1	1	1	1	1
Gas Turbine Fuel		Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Duct Burner Fuel		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions										
Temperature	degree F	-34.3	7.9	15.4	39.1	61	76.8	95.5	76.8	95.5
Relative Humidity	%	70%	69%	70%	70%	76%	62%	36%	62%	36%
Wet Bulb Temperature	degree F	-34.5	6.5	13.5	35.4	56.4	67.3	73.6	67.3	73.6
Pressure	psia	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34	14.34
Gas Turbine Generator Performance										
Electrical Output	kW	178,707	194,008	193,733	194,160	195,081	190,691	177,262	127,127	118,174
Heat Rate - LHV	Btu/kWh	12,234	11,514	11,482	11,377	11,309	11,395	11,694	13,312	13,744
Heat Rate - HHV	Btu/kWh	13,138	12,365	12,330	12,218	12,145	12,237	12,558	14,296	14,759
GTG Heat Input- LHV	MMBtu/hr	2,186	2,234	2,224	2,209	2,206	2,173	2,073	1,692	1,624
GTG Heat Input- HHV	MMBtu/hr	2,348	2,399	2,389	2,372	2,369	2,334	2,226	1,817	1,744
Water / Sprint Injection Rate (per HRSG)	lb/hr	30,810	35,112	37,373	45,497	51,415	56,533	58,985	33,019	35,212
Exhaust Flow (per HRSG)	lb/hr	5,284,172	5,361,248	5,325,683	5,224,172	5,082,642	4,929,648	4,670,663	4,098,512	3,895,002
Exhaust Temperature	degree F	1,001	1,012	1,020	1,046	1,083	1,107	1,127	1,107	1,127
Steam Turbine Generator Performance										
Electrical Output	kW	94,716	98,744	99,747	103,104	108,209	107,240	103,077	88,107	84,708
Duct Burner Fuel Consumption										
Heat Input, LHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heat Input, HHV (per HRSG)	MMBtu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stack Volumetric Analysis, Wet										
Ar	%	0.88%	0.88%	0.88%	0.87%	0.86%	0.85%	0.85%	0.86%	0.86%
CO2	%	4.56%	4.58%	4.59%	4.64%	4.74%	4.80%	4.82%	4.51%	4.55%
H2O	%	5.45%	5.71%	5.85%	6.51%	7.61%	8.39%	8.70%	7.60%	7.89%
N2	%	74.01%	73.81%	73.70%	73.19%	72.33%	71.72%	71.48%	72.33%	72.10%
O2	%	15.07%	14.99%	14.95%	14.76%	14.43%	14.20%	14.11%	14.67%	14.57%
Stack Emissions at Exit										
NOx Emissions										
NOx,@15% O2 Into SCR	ppmvd	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, as NO2 Into SCR (per HRSG)	lb/hr	281.2	287.3	286.1	284.0	283.5	279.1	266.2	217.7	208.9
NOx,@15% O2 Out of SCR	ppmvd	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
NOx, as NO2 Out of SCR (per HRSG)	lb/hr	40.2	41.0	40.9	40.6	40.5	39.9	38.0	31.1	29.8
SCR NOx Removal Efficiency	%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
NH3 Emissions										
NH3 Reacted with NOx (per HRSG)	lb/hr	116.0	118.5	118.0	117.2	116.9	115.1	109.8	89.8	86.2
NH3 slip @ 15% O2	ppmvd	10	10	10	10	10	10	10	10	10
NH3 slip (per HRSG)	lb/hr	24.8	25.3	25.2	25.0	25.0	24.6	23.5	19.2	18.4
CO Emissions										
CO into catalyst	ppmvd	8.4	8.5	8.5	8.7	9.0	9.2	9.2	42.7	43.2
CO into catalyst, @ 15% O2	ppmvd	10.0	10.0	10.0	10.0	10.0	10.0	10.0	50.0	50.0
CO into catalyst (per HRSG)	lb/hr	40.8	41.6	41.5	41.2	41.1	40.5	38.6	157.8	151.4
CO out of catalyst	ppmvd	1.26	1.27	1.28	1.30	1.34	1.37	1.39	4.27	4.32
CO out of catalyst, @ 15% O2	ppmvd	1.50	1.50	1.50	1.50	1.50	1.50	1.50	5.00	5.00
CO out of catalyst (per HRSG)	lb/hr	6.1	6.2	6.2	6.2	6.2	6.1	5.8	15.8	15.1
CO Catalyst Removal Efficiency	%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	90.0%	90.0%
SO2 Emissions										
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvw	0.361	0.360	0.360	0.357	0.353	0.350	0.349	0.353	0.352
SO2 in Exh. Gas @ 15% O2 (assuming no conversion)	ppmvd	0.382	0.382	0.382	0.382	0.382	0.382	0.382	0.382	0.382
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/hr	3.6	3.6	3.6	3.6	3.6	3.5	3.4	2.8	2.6
SO2 in Exhaust Gas (assuming no conversion) (per HRSG)	lb/MMBtu	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152	0.00152
Volatile Organic Compounds										
VOC @ 15% O2	ppmvd	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
VOC as CH4 (per HRSG)	lb/hr	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.1	1.0
VOC % Removal in Catalyst	%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Particulates										
PM10, front including (NH4)2SO4 (per HRSG)	lb/hr	22.3	22.5	22.5	22.4	22.4	22.3	22.0	20.7	20.5
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/hr	37.3	37.5	37.5	37.4	37.4	37.3	37.0	35.7	35.5
PM10, front & back including (NH4)2SO4 (per HRSG)	lb/MMBtu	0.01591	0.01563	0.01569	0.01577	0.01579	0.01598	0.01660	0.01964	0.02033
H2SO4 Emissions										
H2SO4 in Exhaust Gas (per HRSG)	lb/hr	5.45	5.57	5.55	5.51	5.50	5.42	5.17	4.22	4.05
H2SO4 in Exhaust Gas	lb/MMBtu	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232	0.00232
GHG Emissions										
CO2 in Exhaust Gas (per HRSG)	lb/MMBtu	163.45	163.45	163.45	163.45	163.45	163.45	163.45	163.45	163.45
CO2 in Exhaust Gas (per HRSG)	lb/hr	351,785	359,429	357,909	355,437	354,976	349,638	333,538	272,292	261,330
CO2 in Exhaust Gas (per HRSG)	lb/MWh (gross)	1,286.6	1,227.8	1,219.5	1,195.7	1,170.4	1,173.6	1,189.8	1,265.1	1,288.1
CH4 in Exhaust Gas (per HRSG)	lb/MMBtu	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01	1.6535E-01
CH4 in Exhaust Gas (per HRSG)	lb/hr	388.2	396.7	395.0	392.2	391.7	385.8	368.1	300.5	288.4
N2O in Exhaust Gas (per HRSG)	lb/MMBtu	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01	3.9419E-01
N2O in Exhaust Gas (per HRSG)	lb/hr	925.5	945.6	941.6	935.1	933.9	919.9	877.5	716.4	687.5
GHG in Exhaust Gas (per HRSG)	lb/hr	353,098.8	360,771.2	359,245.9	356,763.9	356,301.2	350,944.2	334,783.9	273,309.0	262,306.0
Stack Exit										
Temperature	degree F	181	179	178	175	175	169	174	165	168
Flow Rate (per HRSG)	lb/hr	5,284,172	5,361,248	5,325,683	5,224,172	5,082,642	4,929,648	4,670,663	4,098,512	3,895,002
Flow Rate (per HRSG)	scfm	962,755	977,629	971,630	955,336	932,952	907,363	860,607	753,001	716,298
Flow Rate (per HRSG)	acfm	1,216,120	1,232,310	1,222,622	1,196,409	1,168,283	1,125,549	1,075,325	927,783	886,447
Stack Velocity	ft/sec	57.0	57.7	57.3	56.1	54.7	52.7	50.4	43.5	41.5
Stack Diameter	ft	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3

Notes:
1. Particulate values exclude catalyst and other entrained particles.
2. Emission values do not include heavy metals (lead, mercury, etc.)
3. Differing fuel composition may change the calculated emissions.
4. CTG performance based on performance runs provided by SEI.
5. Fuel based on natural gas analysis provided by NTEC.
6. 35 ppm NOx control on 8000H gas turbine.
8. Stack SO2 content reported with no conversion to SO3.
9. Particulate emissions assume 100% conversion of SO2-SO3, and 100% cove
10. H2SO4 assumes 100% conversion of SO2-SO3, and 100% conversion of SC
11. Greenhouse Gas (GHG) emissions are based on EPA 40 CFR Part 98 emissi
12. 20% margin in Fuel flow and 20% margin in exhaust flow are included.
13. Emissions reported on the basis of pounds per hour are for one combustion tu
14. Emissions estimates are for information only and are NOT guaranteed.

South Shore Energy, LLC - Nemadji Trail Energy Center
Auxiliary Combustion Sources Emissions Calculations

Auxiliary Boiler

Size	100.00	MMBtu/hr
HHV	1,020	Btu/cf
Operation	8,760	hours/year

Auxiliary Boiler Stack Parameters

Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
110.00	290.00	48.00	3.50	27,709	Vertical	Natural Gas

Pollutant	Emission Factors		Source	Emissions	
	lb/MMcf	lb/MMBtu		lb/hr	tpy
NO_X		0.011	Vendor[a]	1.1	4.8
CO		0.0037	BACT	0.4	1.6
$PM/PM_{10}/PM_{2.5}$	7.6	0.01	AP-42[b]	0.7	3.3
SO_2	0.6	0.0006	AP-42[b]	0.06	0.3
VOC		0.0027	BACT	0.3	1.2
H_2SO_4 Mist	--	--	Mass Balance	9E-03	0.04
CO_2	--	117.0	Federal Register[c]	11,698	51,236
CH_4	--	0.0022	Federal Register[c]	0.22	0.97
N_2O	--	0.00022	Federal Register[c]	0.022	0.097
CO_2e	--	--	Federal Register[c]	11,710	51,289

(a) Ultra low-NOx burners
(b) AP-42 Section 1.4 (7/98)
(c) Federal Register - Subpart C of Part 98

Natural Gas Heaters

Size	10.00	MMBtu/hr
HHV	1,020	Btu/cf
Operation	8,760	hours/year
Number of heaters	2	

Natural Gas Heater Stack Parameters

Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
15.00	750.00	25.00	1.67	3,272	Vertical	Natural Gas

Pollutant	Emission Factors		Source	Emissions		Emissions (2 heaters)	
	lb/MMcf	lb/MMBtu		lb/hr	tpy	lb/hr	tpy
NO_X	50.0	0.049	AP-42[a]	0.5	2.1	1.0	4.3
CO	84.0	0.08	AP-42[a]	0.8	3.6	1.6	7.2
$PM/PM_{10}/PM_{2.5}$	7.6	0.01	AP-42[a]	0.07	0.3	0.1	0.7
SO_2	0.6	0.0006	AP-42[a]	5.9E-03	0.03	0.01	0.05
VOC	5.5	0.005	AP-42[a]	0.05	0.2	0.1	0.5
H_2SO_4 Mist	--	--	Mass Balance	9.0E-04	3.9E-03	1.8E-03	7.9E-03
CO_2	--	117.0	Federal Register[b]	1,170	5,124	2,340	10,247
CH_4	--	0.0022	Federal Register[b]	0.022	0.10	0.04	0.19
N_2O	--	0.00022	Federal Register[b]	2.2E-03	0.010	0.00	0.02
CO_2e	--	--	Federal Register[b]	1,171	5,129	2,342	10,258

(a) AP-42 Section 1.4 (7/98)
(b) Federal Register - Subpart C of Part 98

Emergency Diesel Fire Pump

Size	282.0	HP
	1.95	MMBtu/hr
	14.10	gal/hr
Operation	500	hours/year

Emergency Fire Pump Stack Parameters

Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
15.00	1,030	153.90	0.50	1,813	Vertical	Diesel

Pollutant	Emission Factors				Emissions		
	g/kw-hr	g/hp-hr	lb/hp-hr	lb/MMBtu	Source	lb/hr	tpy
NO_X	4.0	3.0	--	--	NSPS[a]	1.9	0.5
CO	3.5	2.6	--	--	NSPS[a]	1.6	0.4
$PM/PM_{10}/PM_{2.5}$	0.2	0.15	--	--	NSPS[a]	0.09	0.02
SO_2	--	--	2.05E-03	--	AP-42[b]	0.6	0.1
VOC	--	1.1	2.51E-03		AP-42[b]	0.7	0.2
H_2SO_4 Mist	--	--	--	--	Mass Balance	0.09	0.02
CO_2	--	--	--	163.1	Federal Register[c]	318.0	79.5
CH_4	--	--	--	0.0066	Federal Register[c]	0.013	3.2E-03
N_2O	--	--	--	0.00132	Federal Register[c]	2.6E-03	6.4E-04
CO_2e	--	--	--	--	Federal Register[c]	319	80

(a) NSPS 40 CFR Part 60, Subpart IIII Limits

NSPS Limits - 40 CFR Part 60, Subpart IIII, (40 CFR 60 Table 4)

	NOx + VOM	CO	PM
g/kW-hr	4.0	3.5	0.20
g/hp-hr	3.0	2.6	0.15

(b) AP-42 Section 3.3 (10/96)

(c) Federal Register - Subpart C of Part 98

South Shore Energy, LLC - Nemadji Trail Energy Center
Auxiliary Combustion Sources Emissions Calculations

Emergency Diesel Generator

Size	1,112	KW
	1,490	hp
	150.0	gal/hr
	20.6	MMBtu/hr
Operation	500	hours/year
Sulfur Content	0.0015	%

137,000	Btu/gal

Emergency Diesel Generator Stack Parameters

Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
15.00	890.00	360.01	0.67	7,540	Vertical	Diesel

	Emission Factors				Emissions		
Pollutant	g/kw-hr	g/hp-hr	lb/hp-hr	lb/MMBtu	Source	lb/hr	tpy
NO_X	6.4	4.8	--	--	NSPS[a]	15.7	3.9
CO	3.5	2.6	--	--	NSPS[a]	8.6	2.1
$PM/PM_{10}/PM_{2.5}$	0.2	0.15	--	--	NSPS[a]	0.5	0.1
SO_2	--	--	1.21E-05	--	AP-42[b]	0.02	4.5E-03
VOC	--	0.32	7.05E-04	--	AP-42[b]	1.1	0.3
H_2SO_4 Mist	--	--	--	--	Mass Balance	2.8E-03	6.9E-04
CO_2	--	--	--	163.1	Federal Register[c]	3,351	838
CH_4	--	--	--	0.0066	Federal Register[c]	1.4E-01	3.4E-02
N_2O	--	--	--	0.00132	Federal Register[c]	2.7E-02	6.8E-03
CO_2e	--	--	--	--	Federal Register[c]	3,362	841

(a) NSPS 40 CFR Part 60, Subapart IIII Limits

NSPS Limits - 40 CFR Part 60, Subapart IIII, (40 CFR 60.4202(a)(2) and 40 CFR 89.112 - Table 1)

	NOx + VOM	CO	PM
g/kW-hr	6.4	3.5	0.20
g/hp-hr	4.8	2.6	0.15

(b) AP-42 Section 3.4 (10/96)
(c) Federal Register - Subpart C of Part 98

Sulfuric Acid Mist

		Conversion Percent	
Assume 10%	of SO_2 is converted to SO_3	10	$SO_2 + 1/2\ O_2 = SO_3$
Assume 100%	of SO_3 is converted to H_2SO_4	100	$SO_3 + H_2O = H_2SO_4$

Name	lb/hr SO_2	lb/hr SO_2 converted to SO_3	lb/hr SO_3 created	lb/hr H_2SO_4 created	tons/year H_2SO_4
Auxiliary Boiler	0.059	5.9E-03	7.4E-03	9.0E-03	3.9E-02
Dew Point Heater	5.9E-03	5.9E-04	7.4E-04	9.0E-04	3.9E-03
Emergency Fire Pump	0.58	5.8E-02	7.2E-02	8.9E-02	2.2E-02
Emergency Diesel Generator	0.02	0.00	0.00	0.00	6.9E-04

Molecular Weights	
SO_2	64.1
SO_3	80.1
H_2SO_4	98.1

CO_2 Equivalent Ratios

Greenhouse Gas			CO_2 Equivalent Ratio
Carbon Dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	25
Nitrous Oxide	10024-97-2	N_2O	298
Hydrofluorocarbons	Various	CHF (various)	12 - 11,700
Perfluorocarbons	Various	CF (various)	6500 - 17,340
Sulfur Hexafluoride	2551-62-4	SF_6	23,900
Chlorofluorocarbons	Various	CCIF (various)	Not Available

South Shore Energy, LLC - Nemadji Trail Energy Center
Storage Tanks

Tank #	Material Stored	Size	VOC Emissions	
		Gallons	lb/year	Tons/year
1 - Day Tank	#2 Fuel Oil	180,000	83.30	4.17E-02
2 - Diesel Generator Tank	#2 Fuel Oil	1,700	0.48	2.40E-04
3 - Fire Pump Tank	#2 Fuel Oil	350	0.1	5.00E-05
			TOTAL: (tpy VOC)	**0.04**

TANKS 4.0.9d Inputs

	Day Tank		Diesel Generator Tank		Fire Pump Tank	
Description	**Value**	**Units**	**Value**	**Units**	**Value**	**Units**
Tank Type	Vertical Fixed Roof Tank		Horizontal Tank		Horizontal Tank	
Location (meteorological data)	Duluth, MN		Duluth, MN		Duluth, MN	
Tank Contents	Distillate Fuel Oil #2		Distillate Fuel Oil #2		Distillate Fuel Oil #2	
Shell Height	30.00	ft	8.04	ft	5.00	ft
Diameter	33.00	ft	6.00	ft	3.45	ft
Avg. Liquid Height	14.07		--		--	
Volume	180,042.51	gal	1,700	gal	350.0	gal
Turnovers	59.94		20.83		20.83	
Net Throughput	10,791,747.84	gal	35,360.00	gal	7291.55	gal
Tank heated (y/n)	n		n		n	
Shell Color/Shade	White		n		n	
Shell Condition	Good		White		White	
Roof Color/Shade	White		Good		Good	
Roof Condition	Good		--		--	
Roof Type	Cone		--		--	
Roof Height	5.00	ft	--		--	
Slope (Cone Roof)	0.30	ft/ft	--		--	
Vacuum Settings (psig)	-0.03		-0.03		-0.03	
Pressure Settings (psig)	0.03		0.03		0.03	
Working Loss	69.18	lb/yr	0.34	lb/yr	0.07	lb/yr
Breathing Loss	14.11	lb/yr	0.14	lb/yr	0.03	lb/yr
Total losses	83.30	lb/yr	0.48	lb/yr	0.10	lb/yr
Total Emissions	**4.17E-02**	**tpy**	**2.40E-04**	**tpy**	**5.00E-05**	**tpy**

South Shore Energy, LLC - Nemadji Trail Energy Center
Greenhouse Gas Emissions from SF_6 in Circuit Breakers

Inputs	
Number of 19 kV Generator Circuit Breakers	2
Quantity of SF_6 in each 19 kV Breaker (lb)	23.0
Number of 345 kV Generator Circuit Breakers	3
Quantity of SF_6 in each 345 kV Breaker (lb)	687.0
Global Warming Potential of SF6 (100yr)	22,800

Fugitive Emissions of SF6 due to leakage

	Number of Units	Quantity of SF_6 per Breaker (lbs)	Emissions of SF_6 Per Breaker[a] (lbs/yr)	Total SF_6 Emissions (lbs/yr)	Global Warming Potential	Total CO_2e Emissions (tons/yr)
19 kV Breakers	2	23.0	0.12	0.23	22,800	2.6
345 kV Breakers	3	687.0	3.44	10.31	22,800	117.5
Total				**10.5**		**120**

(a) Based on a maximum SF_6 leakage rate of 0.5% per year

South Shore Energy, LLC - Nemadji Trail Energy Center
Emissions from Paved Haul Roads

Paved Haul Road Emissions

$E = k * (sL)^{0.91} * (W)^{1.02}$ Equation 1 from AP 42 Section 13.2.1.3.

where E is the particulate emission factor having the units matching k

Parameter	Value	Description of parameter
sL	2.4	Ubiquitous Silt Loading Default Value, g/m^2
W	see below	Mean vehicle weight [(loaded truck weight + unloaded truck weight)/2], tons
VMT	see below	Vehicle miles traveled (length traveled round trip)
VMT/hr	see below	Vehicle miles traveled per hour = VMT*maximum trips per hour
VMT/yr	see below	Vehicle miles traveled per year = VMT*maximum trips per year

	k (lb/VMT)
PM2.5	0.00054
PM10	0.0022
PM30 (TSP)	0.011

Notes: Constant k, lb/VMT is from AP 42 Table 13.2.1-1

	Vehicle Type	Paved	Max # Trips/hour	Max # Trips/yr[a]	VMT - Length (round trip) meters	VMT - Length (round trip) (miles)	Truck Weight[b] Loaded tons	Truck Weight[b] Unloaded tons	Factor "E" lb PM/VMT	Factor "E" lb PM10/VMT	Factor "E" lb PM2.5/VMT	Traveled VMT/hr	Traveled VMT/yr	Emissions Uncontrolled lb PM/hr	Emissions Uncontrolled PM tpy	Emissions Uncontrolled lb PM10/hr	Emissions Uncontrolled PM10 tpy	Emissions Uncontrolled lb PM2.5/hr	Emissions Uncontrolled PM2.5 tpy
Miscellaneous Deliveries paved (single-trip: loop)	generic haul truck	yes	6	520	837	0.52	40	15	0.72	0.14	0.04	3.12	270.40	2.24	0.10	0.45	0.02	0.11	0.005

(a) On average less than 10 trucks per week are expected for delivery or removal; therefore, 10 trucks per week * 52 weeks per year = 520 trips per year

(b) Based on generic truck weight of the trucks that will be traveling onsite

South Shore Energy, LLC - Nemadji Trail Energy Center
Emissions from Piping Fugitives

	VOC	CO_2e
Total Emissions from Piping Fugitives (tpy)	**10.4**	**976.6**

Natural Gas

				VOC[b]			CO_2e[c,d]		
Equipment Type	**Service**	**Quantity**	**Factor[a] (kg/hr/source)**	**Maximum emissions (lb/hr)**	**Maximum theoretical emissions (tpy)**	**Potential to emit (tpy)**	**Maximum emissions (lb/hr)**	**Maximum theoretical emissions (tpy)**	**Potential to emit (tpy)**
Connectors	Natural Gas	279	2.00E-04	0.01	0.04	0.04	3.00	13.13	13.13
Flanges	Natural Gas	465	3.90E-04	0.03	0.12	0.12	9.75	42.68	42.68
Open Ended Lines	Natural Gas	30	2.00E-03	0.01	0.04	0.04	3.22	14.12	14.12
Valves	Natural Gas	856	4.50E-03	0.59	2.60	2.60	207.00	906.65	906.65
			Total	**0.64**	**2.80**	**2.80**	**222.97**	**976.59**	**976.59**

(a) 1995 Protocol for Equipment Leak Emission Estimates- EPA-453/R-95-017
(b) Since methane is not a VOC, the maximum VOC is calculated at the minimum methane content.
93.00% minimum wt% methane
(c) Since methane is GHG, the maximum CO_2e is calculated at the maximum methane content.
97.50% maximum wt% methane
(d) Methane Global Warming Potential (40 CFR 98) was applied 25

Fuel Oil

				VOC[b]		
Equipment Type	**Service**	**Quantity**	**Factor[a] (kg/hr/source)**	**Maximum emissions (lb/hr)**	**Maximum theoretical emissions (tpy)**	**Potential to emit (tpy)**
Connectors	Light Oil	52	2.10E-04	0.02	0.11	0.11
Flanges	Light Oil	420	1.10E-04	0.10	0.45	0.45
Open Ended Lines	Light Oil	0	1.40E-03	0.00	0.00	0.00
Valves	Light Oil	291	2.50E-03	1.60	7.02	7.02
			Total	**1.73**	**7.58**	**7.58**

(a) 1995 Protocol for Equipment Leak Emission Estimates- EPA-453/R-95-017
(b) Assume all emissions are VOC

Note: The 1995 Protocol for Equipment Leak Emission Rates is the most relevant calculation reference and is a reputable reference document that is widely referenced.

South Shore Energy, LLC - Nemadji Trail Energy Center
Combined Cycle HAPs Emissions - New Emission Sources

Hours of Operation

Combustion Turbine Natural Gas Hours =	8,760	hours per year
Combustion Turbine Fuel Oil Hours =	0	hours per year
Duct Burner =	0	hours per year
Auxillary Boiler =	8,760	hours per year
Natural Gas Heater =	8,760	hours per year
Emergency Diesel Fire Pump =	500	hours per year
Emergency Diesel Generator =	500	hours per year

Natural Gas Usage

	mmBtu/hr	mmCF/hr	
			1,020 MMBtu/MMcf
Combustion Turbine (Natural Gas) =	3,665	--	
Combustion Turbine (Fuel Oil) =	3,021	--	
Duct Burner =	1,006	0.987	
Auxillary Boiler =	100.0	0.098	
Natural Gas Heaters =	20.0	0.020	2 Natural Gas Heaters
Emergency Diesel Fire Pump =	1.95	--	
Emergency Diesel Generator =	20.6	--	

Total Facility: Hazardous Air Pollutants Emissions

HAP	Maximum Potential Emissions tpy
1st Maximum: Formaldehyde	3.28
2nd Maximum: Toluene	2.09
3rd Maximum: Xylene	1.03
All HAPs	9.33

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
	CAS		Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical		POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMcf	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
2-Methylnaphthalene	97-57-6	POM							2.4E-05	2.4E-05	0.0E+00	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.2E-05
3-Methylchloranthrene	56-49-5	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07							9.3E-07
7,12-Dimethylbenz(a)anthracene		POM							1.6E-05	1.6E-05	0.0E+00	1.6E-06	6.9E-06	3.1E-07	1.4E-06							8.2E-06
Acenaphthene	83-32-9	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.42E-06	2.8E-06	6.9E-07	4.68E-06	9.6E-05	2.4E-05	2.6E-05
Acenaphthylene	203-96-8	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	5.06E-06	9.9E-06	2.5E-06	9.23E-06	1.9E-04	4.7E-05	5.1E-05
Acetaldehyde	75-07-0		4.0E-05	1.5E-01	6.4E-01											7.67E-04	1.5E-03	3.7E-04	2.52E-05	5.2E-04	1.3E-04	6.4E-01
Acrolein	107-02-8		6.4E-06	2.3E-02	1.0E-01											9.25E-05	1.8E-04	4.5E-05	7.88E-06	1.6E-04	4.0E-05	1.0E-01
Anthracene	120-12-7	POM							2.4E-06	2.4E-06	0.0E+00	2.4E-07	1.0E-06	4.7E-08	2.1E-07	1.87E-06	3.6E-06	9.1E-07	1.23E-06	2.5E-05	6.3E-06	8.5E-06
Arsenic	7440-38-2					1.1E-05	3.3E-02	0.0E+00	2.0E-04	2.0E-04	0.0E+00	2.0E-05	8.6E-05	3.9E-06	1.7E-05							1.0E-04
Benz(a)anthracene	56-55-3	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.68E-06	3.3E-06	8.2E-07	6.22E-07	1.3E-05	3.2E-06	4.9E-06
Benzene	71-43-2		1.2E-05	4.4E-02	1.9E-01	5.5E-05	1.7E-01	0.0E+00	2.1E-03	2.1E-03	0.0E+00	2.1E-04	9.0E-04	4.1E-05	1.8E-04	9.33E-04	1.8E-03	4.5E-04	7.76E-04	1.6E-02	4.0E-03	2.0E-01
Benzo(a)pyrene	50-32-8	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	1.88E-07	3.7E-07	9.2E-08	2.57E-07	5.3E-06	1.3E-06	2.0E-06
Benzo(b)fluoranthene	205-99-2	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	9.91E-08	1.9E-07	4.8E-08	1.11E-06	2.3E-05	5.7E-06	6.7E-06
Benzo(g,h,l)perylene	191-24-2	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	4.89E-07	9.5E-07	2.4E-07	5.56E-07	1.1E-05	2.9E-06	3.7E-06
Benzo(k)fluoranthene	205-82-3	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.55E-07	3.0E-07	7.6E-08	2.18E-07	4.5E-06	1.1E-06	2.1E-06
Beryllium	7440-41-7					3.1E-07	9.4E-04	0.0E+00	1.2E-05	1.2E-05	0.0E+00	1.2E-06	5.2E-06	2.4E-07	1.0E-06							6.2E-06
1,3-Butadiene	106-99-0		4.3E-07	1.6E-03	6.9E-03	1.6E-05	4.8E-02	0.0E+00								3.91E-05	7.6E-05	1.9E-05				6.9E-03
Cadmium	7440-43-7					4.8E-06	1.5E-02	0.0E+00	1.1E-03	1.1E-03	0.0E+00	1.1E-04	4.7E-04	2.2E-05	9.4E-05							5.7E-04
Chromium	7440-47-3					1.1E-05	3.3E-02	0.0E+00	1.4E-03	1.4E-03	0.0E+00	1.4E-04	6.0E-04	2.7E-05	1.2E-04							7.2E-04
Chrysene	218-01-9	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.53E-07	6.9E-07	1.7E-07	1.53E-06	3.1E-05	7.9E-06	9.0E-06
Cobalt	7440-48-4								8.4E-05	8.3E-05	0.0E+00	8.2E-06	3.6E-05	1.6E-06	7.2E-06							4.3E-05
Dibenzo(a,h)anthracene	53-70-3	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	5.83E-07	1.1E-06	2.8E-07	3.46E-07	7.1E-06	1.8E-06	2.7E-06
Dichlorobenzene	25321-22-6								1.2E-03	1.2E-03	0.0E+00	1.2E-04	5.2E-04	2.4E-05	1.0E-04							6.2E-04
Ethyl benzene	100-41-4		3.2E-05	1.2E-01	5.1E-01																	5.1E-01
Fluoranthene	206-44-0	POM							3.0E-06	3.0E-06	0.0E+00	2.9E-07	1.3E-06	5.9E-08	2.6E-07	7.61E-06	1.5E-05	3.7E-06	4.03E-06	8.3E-05	2.1E-05	2.6E-05
Fluorene	86-73-7	POM							2.8E-06	2.8E-06	0.0E+00	2.7E-07	1.2E-06	5.5E-08	2.4E-07	2.92E-05	5.7E-05	1.4E-05	1.28E-05	2.6E-04	6.6E-05	8.1E-05
Formaldehyde	50-00-0		2.0E-04	7.4E-01	3.2E+00	2.8E-04	8.5E-01	0.0E+00	7.5E-02	7.4E-02	0.0E+00	7.4E-03	3.2E-02	1.5E-03	6.4E-03	1.18E-03	2.3E-03	5.8E-04	7.89E-05	1.6E-03	4.1E-04	3.3E+00
Hexane	110-54-3								1.8E+00	1.8E+00	0.0E+00	1.8E-01	7.7E-01	3.5E-02	1.5E-01							9.3E-01
Indeno(1,2,3-cd)pyrene	193-39-5	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.75E-07	7.3E-07	1.8E-07	4.14E-07	8.5E-06	2.1E-06	3.2E-06
Manganese	7439-96-5					7.9E-04	2.4E+00	0.0E+00	3.8E-04	3.7E-04	0.0E+00	3.7E-05	1.6E-04	7.5E-06	3.3E-05							2.0E-04
Mercury	7439-97-6					1.2E-06	3.6E-03	0.0E+00	2.6E-04	2.6E-04	0.0E+00	2.5E-05	1.1E-04	5.1E-06	2.2E-05							1.3E-04
Naphthalene	91-20-3		1.3E-06	4.8E-03	2.1E-02	3.5E-05	1.1E-01	0.0E+00	6.1E-04	6.0E-04	0.0E+00	6.0E-05	2.6E-04	1.2E-05	5.2E-05	8.48E-05	1.7E-04	4.1E-05	1.30E-04	2.7E-03	6.7E-04	2.2E-02
Nickel	7440-02-0					4.6E-06	1.4E-02	0.0E+00	2.1E-03	2.1E-03	0.0E+00	2.1E-04	9.0E-04	4.1E-05	1.8E-04							1.1E-03
PAH			2.2E-06	8.1E-03	3.5E-02	4.0E-05	1.2E-01	0.0E+00														3.5E-02
Phenanathrene	85-01-8	POM							1.7E-05	1.7E-05	0.0E+00	1.7E-06	7.3E-06	3.3E-07	1.5E-06	2.94E-05	5.7E-05	1.4E-05	4.08E-05	8.4E-04	2.1E-04	2.3E-04
Propylene																2.58E-03	5.0E-03	1.3E-03	2.79E-03	5.7E-02	1.4E-02	1.6E-02
Proplylene Oxide	75-56-9		2.9E-05	1.1E-01	4.7E-01																	4.7E-01
Pyrene	129-00-0	POM							5.0E-06	4.9E-06	0.0E+00	4.9E-07	2.1E-06	9.8E-08	4.3E-07	4.78E-06	9.3E-06	2.3E-06	3.71E-06	7.6E-05	1.9E-05	2.4E-05
Selenium	7782-49-2					2.5E-05	7.6E-02	0.0E+00	2.4E-05	2.4E-05	0.0E+00	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.2E-05
Toluene	108-88-3		1.3E-04	4.8E-01	2.1E+00				3.4E-03	3.4E-03	0.0E+00	3.3E-04	1.5E-03	6.7E-05	2.9E-04	4.09E-04	8.0E-04	2.0E-04	2.81E-04	5.8E-03	1.4E-03	2.1E+00
Xylene	1330-20-7		6.4E-05	2.3E-01	1.0E+00											2.85E-04	5.6E-04	1.4E-04	1.93E-04	4.0E-03	9.9E-04	1.0E+00
		TOTAL		1.90	8.34		3.85	0.00		1.86	0.00	0.19	0.81	0.04	1.6E-01		1.3E-02	3.1E-03				9.33

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.

(b) Emission factors from AP-42 Section 1.4, Updated 7/1998

(c) Emission factors from AP-42 Section 3.3, Updated 10/1996

(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
			Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical	CAS	POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
Lead						1.4E-05	4.2E-02	0.0E+00	5.0E-04	4.9E-04	0.0E+00	4.9E-05	2.1E-04	9.8E-06	4.3E-05							2.6E-04

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.

(b) Emission factors from AP-42 Section 1.4, Updated 7/1998

(c) Emission factors from AP-42 Section 3.3, Updated 10/1996

(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

South Shore Energy, LLC - Nemadji Trail Energy Center
Combined Cycle HAPs Emissions - New Emission Sources

Hours of Operation

Combustion Turbine Natural Gas Hours =	0	hours per year
Combustion Turbine Fuel Oil Hours =	0	hours per year
Duct Burner =	8,760	hours per year
Auxillary Boiler =	8,760	hours per year
Natural Gas Heater =	8,760	hours per year
Emergency Diesel Fire Pump =	500	hours per year
Emergency Diesel Generator =	500	hours per year

Total Facility: Hazardous Air Pollutants Emissions

HAP	Maximum Potential Emissions tpy
1st Maximum: Hexane	8.71
2nd Maximum: Formaldehyde	0.36
3rd Maximum: Toluene	0.02
All HAPs	9.16

Natural Gas Usage

	mmBtu/hr	mmCF/hr	
			1,020 MMBtu/MMcf
Combustion Turbine (Natural Gas) =	3,665	--	
Combustion Turbine (Fuel Oil) =	3,021	--	
Duct Burner =	1,006	0.987	
Auxillary Boiler =	100.0	0.098	
Natural Gas Heater =	20.0	0.020	2 Natural Gas Heaters
Emergency Diesel Fire Pump =	1.95	--	
Emergency Diesel Generator =	20.6	--	

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
	CAS		Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical		POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMcf	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
2-Methylnaphthalene	97-57-6	POM							2.4E-05	2.4E-05	1.0E-04	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.2E-04
3-Methylchloranthrene	56-49-5	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07							8.7E-06
7,12-Dimethylbenz(a)anthracene		POM							1.6E-05	1.6E-05	6.9E-05	1.6E-06	6.9E-06	3.1E-07	1.4E-06							7.7E-05
Acenaphthene	83-32-9	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.42E-06	2.8E-06	6.9E-07	4.68E-06	9.6E-05	2.4E-05	3.3E-05
Acenaphthylene	203-96-8	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	5.06E-06	9.9E-06	2.5E-06	9.23E-06	1.9E-04	4.7E-05	5.9E-05
Acetaldehyde	75-07-0		4.0E-05	1.5E-01	0.0E+00											7.67E-04	1.5E-03	3.7E-04	2.52E-05	5.2E-04	1.3E-04	5.0E-04
Acrolein	107-02-8		6.4E-06	2.3E-02	0.0E+00											9.25E-05	1.8E-04	4.5E-05	7.88E-06	1.6E-04	4.0E-05	8.6E-05
Anthracene	120-12-7	POM							2.4E-06	2.4E-06	1.0E-05	2.4E-07	1.0E-06	4.7E-08	2.1E-07	1.87E-06	3.6E-06	9.1E-07	1.23E-06	2.5E-05	6.3E-06	1.9E-05
Arsenic	7440-38-2					1.1E-05	3.3E-02	0.0E+00	2.0E-04	2.0E-04	8.6E-04	2.0E-05	8.6E-05	3.9E-06	1.7E-05							9.7E-04
Benz(a)anthracene	56-55-3	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.68E-06	3.3E-06	8.2E-07	6.22E-07	1.3E-05	3.2E-06	1.3E-05
Benzene	71-43-2		1.2E-05	4.4E-02	0.0E+00	5.5E-05	1.7E-01	0.0E+00	2.1E-03	2.1E-03	9.1E-03	2.1E-04	9.0E-04	4.1E-05	1.8E-04	9.33E-04	1.8E-03	4.5E-04	7.76E-04	1.6E-02	4.0E-03	1.5E-02
Benzo(a)pyrene	50-32-8	POM							1.2E-06	1.2E-06	5.2E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	1.88E-07	3.7E-07	9.2E-08	2.57E-07	5.3E-06	1.3E-06	7.2E-06
Benzo(b)fluoranthene	205-99-2	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	9.91E-08	1.9E-07	4.8E-08	1.11E-06	2.3E-05	5.7E-06	1.4E-05
Benzo(g,h,I)perylene	191-24-2	POM							1.2E-06	1.2E-06	5.2E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	4.89E-07	9.5E-07	2.4E-07	5.56E-07	1.1E-05	2.9E-06	8.9E-06
Benzo(k)fluoranthene	205-82-3	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.55E-07	3.0E-07	7.6E-08	2.18E-07	4.5E-06	1.1E-06	9.9E-06
Beryllium	7440-41-7					3.1E-07	9.4E-04	0.0E+00	1.2E-05	1.2E-05	5.2E-05	1.2E-06	5.2E-06	2.4E-07	1.0E-06							5.8E-05
1,3-Butadiene	106-99-0		4.3E-07	1.6E-03	0.0E+00	1.6E-05	4.8E-02	0.0E+00								3.91E-05	7.6E-05	1.9E-05				1.9E-05
Cadmium	7440-43-7					4.8E-06	1.5E-02	0.0E+00	1.1E-03	1.1E-03	4.8E-03	1.1E-04	4.7E-04	2.2E-05	9.4E-05							5.3E-03
Chromium	7440-47-3					1.1E-05	3.3E-02	0.0E+00	1.4E-03	1.4E-03	6.0E-03	1.4E-04	6.0E-04	2.7E-05	1.2E-04							6.8E-03
Chrysene	218-01-9	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.53E-07	6.9E-07	1.7E-07	1.53E-06	3.1E-05	7.9E-06	1.7E-05
Cobalt	7440-48-4								8.4E-05	8.3E-05	3.6E-04	8.2E-06	3.6E-05	1.6E-06	7.2E-06							4.1E-04
Dibenzo(a,h)anthracene	53-70-3	POM							1.2E-06	1.2E-06	5.2E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	5.83E-07	1.1E-06	2.8E-07	3.46E-07	7.1E-06	1.8E-06	7.9E-06
Dichlorobenzene	25321-22-6								1.2E-03	1.2E-03	5.2E-03	1.2E-04	5.2E-04	2.4E-05	1.0E-04							5.8E-03
Ethyl benzene	100-41-4		3.2E-05	1.2E-01	0.0E+00																	0.0E+00
Fluoranthene	206-44-0	POM							3.0E-06	3.0E-06	1.3E-05	2.9E-07	1.3E-06	5.9E-08	2.6E-07	7.61E-06	1.5E-05	3.7E-06	4.03E-06	8.3E-05	2.1E-05	3.9E-05
Fluorene	86-73-7	POM							2.8E-06	2.8E-06	1.2E-05	2.7E-07	1.2E-06	5.5E-08	2.4E-07	2.92E-05	5.7E-05	1.4E-05	1.28E-05	2.6E-04	6.6E-05	9.4E-05
Formaldehyde	50-00-0		2.0E-04	7.4E-01	0.0E+00	2.8E-04	8.5E-01	0.0E+00	7.5E-02	7.4E-02	3.2E-01	7.4E-03	3.2E-02	1.5E-03	6.4E-03	1.18E-03	2.3E-03	5.8E-04	7.89E-05	1.6E-03	4.1E-04	3.6E-01
Hexane	110-54-3								1.8E+00	1.8E+00	7.8E+00	1.8E-01	7.7E-01	3.5E-02	1.5E-01							8.7E+00
Indeno(1,2,3-cd)pyrene	193-39-5	POM							1.8E-06	1.8E-06	7.8E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.75E-07	7.3E-07	1.8E-07	4.14E-07	8.5E-06	2.1E-06	1.1E-05
Manganese	7439-96-5					7.9E-04	2.4E+00	0.0E+00	3.8E-04	3.7E-04	1.6E-03	3.7E-05	1.6E-04	7.5E-06	3.3E-05							1.8E-03
Mercury	7439-97-6					1.2E-06	3.6E-03	0.0E+00	2.6E-04	2.6E-04	1.1E-03	2.5E-05	1.1E-04	5.1E-06	2.2E-05							1.3E-03
Naphthalene	91-20-3		1.3E-06	4.8E-03	0.0E+00	3.5E-05	1.1E-01	0.0E+00	6.1E-04	6.0E-04	2.6E-03	6.0E-05	2.6E-04	1.2E-05	5.2E-05	8.48E-05	1.7E-04	4.1E-05	1.30E-04	2.7E-03	6.7E-04	3.7E-03
Nickel	7440-02-0					4.6E-06	1.4E-02	0.0E+00	2.1E-03	2.1E-03	9.1E-03	2.1E-04	9.0E-04	4.1E-05	1.8E-04							1.0E-02
PAH			2.2E-06	8.1E-03	0.0E+00	4.0E-05	1.2E-01	0.0E+00														0.0E+00
Phenanathrene	85-01-8	POM							1.7E-05	1.7E-05	7.3E-05	1.7E-06	7.3E-06	3.3E-07	1.5E-06	2.94E-05	5.7E-05	1.4E-05	4.08E-05	8.4E-04	2.1E-04	3.1E-04
Propylene																2.58E-03	5.0E-03	1.3E-03	2.79E-03	5.7E-02	1.4E-02	1.6E-02
Proplylene Oxide	75-56-9		2.9E-05	1.1E-01	0.0E+00																	0.0E+00
Pyrene	129-00-0	POM							5.0E-06	4.9E-06	2.2E-05	4.9E-07	2.1E-06	9.8E-08	4.3E-07	4.78E-06	9.3E-06	2.3E-06	3.71E-06	7.6E-05	1.9E-05	4.6E-05
Selenium	7782-49-2					2.5E-05	7.6E-02	0.0E+00	2.4E-05	2.4E-05	1.0E-04	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.2E-04
Toluene	108-88-3		1.3E-04	4.8E-01	0.0E+00				3.4E-03	3.4E-03	1.5E-02	3.3E-04	1.5E-03	6.7E-05	2.9E-04	4.09E-04	8.0E-04	2.0E-04	2.81E-04	5.8E-03	1.4E-03	1.8E-02
Xylene	1330-20-7		6.4E-05	2.3E-01	0.0E+00											2.85E-04	5.6E-04	1.4E-04	1.93E-04	4.0E-03	9.9E-04	1.1E-03
		TOTAL		1.90	0.00		3.85	0.00		1.86	8.16	0.19	0.81	0.04	1.6E-01		1.3E-02	3.1E-03				9.16

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.
(b) Emission factors from AP-42 Section 1.4, Updated 7/1998
(c) Emission factors from AP-42 Section 3.3, Updated 10/1996
(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
			Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical	CAS	POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
Lead						1.4E-05	4.2E-02	0.0E+00	5.0E-04	4.9E-04	2.2E-03	4.9E-05	2.1E-04	9.8E-06	4.3E-05							2.4E-03

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.
(b) Emission factors from AP-42 Section 1.4, Updated 7/1998
(c) Emission factors from AP-42 Section 3.3, Updated 10/1996
(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

South Shore Energy, LLC - Nemadji Trail Energy Center
Combined Cycle HAPs Emissions - New Emission Sources

Hours of Operation

Combustion Turbine Natural Gas Hours =	0	hours per year
Combustion Turbine Fuel Oil Hours =	500	hours per year
Duct Burner =	8,260	hours per year
Auxillary Boiler =	8,760	hours per year
Natural Gas Heater =	8,760	hours per year
Emergency Diesel Fire Pump =	500	hours per year
Emergency Diesel Generator =	500	hours per year

Total Facility: Hazardous Air Pollutants Emissions

HAP	Maximum Potential Emissions tpy
1st Maximum: Hexane	8.26
2nd Maximum: Manganese	0.60
3rd Maximum: Formaldehyde	0.56
All HAPs	9.65

Natural Gas Usage

1,020 MMBtu/MMcf

	mmBtu/hr	mmCF/hr	
Combustion Turbine (Natural Gas) =	3,665	--	
Combustion Turbine (Fuel Oil) =	3,021	--	
Duct Burner =	1,006	0.987	
Auxillary Boiler =	100.0	0.098	
Natural Gas Heater =	20.0	0.020	2 Natural Gas Heaters
Emergency Diesel Fire Pump =	1.95	--	
Emergency Diesel Generator =	20.6	--	

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
	CAS		Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical		POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMcf	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
2-Methylnaphthalene	97-57-6	POM							2.4E-05	2.4E-05	9.8E-05	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.1E-04
3-Methylchloranthrene	56-49-5	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07							8.3E-06
7,12-Dimethylbenz(a)anthracene		POM							1.6E-05	1.6E-05	6.5E-05	1.6E-06	6.9E-06	3.1E-07	1.4E-06							7.3E-05
Acenaphthene	83-32-9	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.42E-06	2.8E-06	6.9E-07	4.68E-06	9.6E-05	2.4E-05	3.3E-05
Acenaphthylene	203-96-8	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	5.06E-06	9.9E-06	2.5E-06	9.23E-06	1.9E-04	4.7E-05	5.8E-05
Acetaldehyde	75-07-0		4.0E-05	1.5E-01	0.0E+00											7.67E-04	1.5E-03	3.7E-04	2.52E-05	5.2E-04	1.3E-04	5.0E-04
Acrolein	107-02-8		6.4E-06	2.3E-02	0.0E+00											9.25E-05	1.8E-04	4.5E-05	7.88E-06	1.6E-04	4.0E-05	8.6E-05
Anthracene	120-12-7	POM							2.4E-06	2.4E-06	9.8E-06	2.4E-07	1.0E-06	4.7E-08	2.1E-07	1.87E-06	3.6E-06	9.1E-07	1.23E-06	2.5E-05	6.3E-06	1.8E-05
Arsenic	7440-38-2					1.1E-05	3.3E-02	8.3E-03	2.0E-04	2.0E-04	8.1E-04	2.0E-05	8.6E-05	3.9E-06	1.7E-05							9.2E-03
Benz(a)anthracene	56-55-3	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.68E-06	3.3E-06	8.2E-07	6.22E-07	1.3E-05	3.2E-06	1.2E-05
Benzene	71-43-2		1.2E-05	4.4E-02	0.0E+00	5.5E-05	1.7E-01	4.2E-02	2.1E-03	2.1E-03	8.6E-03	2.1E-04	9.0E-04	4.1E-05	1.8E-04	9.33E-04	1.8E-03	4.5E-04	7.76E-04	1.6E-02	4.0E-03	5.6E-02
Benzo(a)pyrene	50-32-8	POM							1.2E-06	1.2E-06	4.9E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	1.88E-07	3.7E-07	9.2E-08	2.57E-07	5.3E-06	1.3E-06	6.9E-06
Benzo(b)fluoranthene	205-99-2	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	9.91E-08	1.9E-07	4.8E-08	1.11E-06	2.3E-05	5.7E-06	1.4E-05
Benzo(g,h,I)perylene	191-24-2	POM							1.2E-06	1.2E-06	4.9E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	4.89E-07	9.5E-07	2.4E-07	5.56E-07	1.1E-05	2.9E-06	8.6E-06
Benzo(k)fluoranthene	205-82-3	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.55E-07	3.0E-07	7.6E-08	2.18E-07	4.5E-06	1.1E-06	9.5E-06
Beryllium	7440-41-7					3.1E-07	9.4E-04	2.3E-04	1.2E-05	1.2E-05	4.9E-05	1.2E-06	5.2E-06	2.4E-07	1.0E-06							2.9E-04
1,3-Butadiene	106-99-0		4.3E-07	1.6E-03	0.0E+00	1.6E-05	4.8E-02	1.2E-02								3.91E-05	7.6E-05	1.9E-05				1.2E-02
Cadmium	7440-43-7					4.8E-06	1.5E-02	3.6E-03	1.1E-03	1.1E-03	4.5E-03	1.1E-04	4.7E-04	2.2E-05	9.4E-05							8.7E-03
Chromium	7440-47-3					1.1E-05	3.3E-02	8.3E-03	1.4E-03	1.4E-03	5.7E-03	1.4E-04	6.0E-04	2.7E-05	1.2E-04							1.5E-02
Chrysene	218-01-9	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.53E-07	6.9E-07	1.7E-07	1.53E-06	3.1E-05	7.9E-06	1.6E-05
Cobalt	7440-48-4								8.4E-05	8.3E-05	3.4E-04	8.2E-06	3.6E-05	1.6E-06	7.2E-06							3.9E-04
Dibenzo(a,h)anthracene	53-70-3	POM							1.2E-06	1.2E-06	4.9E-06	1.2E-07	5.2E-07	2.4E-08	1.0E-07	5.83E-07	1.1E-06	2.8E-07	3.46E-07	7.1E-06	1.8E-06	7.6E-06
Dichlorobenzene	25321-22-6								1.2E-03	1.2E-03	4.9E-03	1.2E-04	5.2E-04	2.4E-05	1.0E-04							5.5E-03
Ethyl benzene	100-41-4		3.2E-05	1.2E-01	0.0E+00																	0.0E+00
Fluoranthene	206-44-0	POM							3.0E-06	3.0E-06	1.2E-05	2.9E-07	1.3E-06	5.9E-08	2.6E-07	7.61E-06	1.5E-05	3.7E-06	4.03E-06	8.3E-05	2.1E-05	3.8E-05
Fluorene	86-73-7	POM							2.8E-06	2.8E-06	1.1E-05	2.7E-07	1.2E-06	5.5E-08	2.4E-07	2.92E-05	5.7E-05	1.4E-05	1.28E-05	2.6E-04	6.6E-05	9.3E-05
Formaldehyde	50-00-0		2.0E-04	7.4E-01	0.0E+00	2.8E-04	8.5E-01	2.1E-01	7.5E-02	7.4E-02	3.1E-01	7.4E-03	3.2E-02	1.5E-03	6.4E-03	1.18E-03	2.3E-03	5.8E-04	7.89E-05	1.6E-03	4.1E-04	5.6E-01
Hexane	110-54-3								1.8E+00	1.8E+00	7.3E+00	1.8E-01	7.7E-01	3.5E-02	1.5E-01							8.3E+00
Indeno(1,2,3-cd)pyrene	193-39-5	POM							1.8E-06	1.8E-06	7.3E-06	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.75E-07	7.3E-07	1.8E-07	4.14E-07	8.5E-06	2.1E-06	1.1E-05
Manganese	7439-96-5					7.9E-04	2.4E+00	6.0E-01	3.8E-04	3.7E-04	1.5E-03	3.7E-05	1.6E-04	7.5E-06	3.3E-05							6.0E-01
Mercury	7439-97-6					1.2E-06	3.6E-03	9.1E-04	2.6E-04	2.6E-04	1.1E-03	2.5E-05	1.1E-04	5.1E-06	2.2E-05							2.1E-03
Naphthalene	91-20-3		1.3E-06	4.8E-03	0.0E+00	3.5E-05	1.1E-01	2.6E-02	6.1E-04	6.0E-04	2.5E-03	6.0E-05	2.6E-04	1.2E-05	5.2E-05	8.48E-05	1.7E-04	4.1E-05	1.30E-04	2.7E-03	6.7E-04	3.0E-02
Nickel	7440-02-0					4.6E-06	1.4E-02	3.5E-03	2.1E-03	2.1E-03	8.6E-03	2.1E-04	9.0E-04	4.1E-05	1.8E-04							1.3E-02
PAH			2.2E-06	8.1E-03	0.0E+00	4.0E-05	1.2E-01	3.0E-02														3.0E-02
Phenanathrene	85-01-8	POM							1.7E-05	1.7E-05	6.9E-05	1.7E-06	7.3E-06	3.3E-07	1.5E-06	2.94E-05	5.7E-05	1.4E-05	4.08E-05	8.4E-04	2.1E-04	3.0E-04
Propylene																2.58E-03	5.0E-03	1.3E-03	2.79E-03	5.7E-02	1.4E-02	1.6E-02
Proplylene Oxide	75-56-9		2.9E-05	1.1E-01	0.0E+00																	0.0E+00
Pyrene	129-00-0	POM							5.0E-06	4.9E-06	2.0E-05	4.9E-07	2.1E-06	9.8E-08	4.3E-07	4.78E-06	9.3E-06	2.3E-06	3.71E-06	7.6E-05	1.9E-05	4.4E-05
Selenium	7782-49-2					2.5E-05	7.6E-02	1.9E-02	2.4E-05	2.4E-05	9.8E-05	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.9E-02
Toluene	108-88-3		1.3E-04	4.8E-01	0.0E+00				3.4E-03	3.4E-03	1.4E-02	3.3E-04	1.5E-03	6.7E-05	2.9E-04	4.09E-04	8.0E-04	2.0E-04	2.81E-04	5.8E-03	1.4E-03	1.7E-02
Xylene	1330-20-7		6.4E-05	2.3E-01	0.0E+00											2.85E-04	5.6E-04	1.4E-04	1.93E-04	4.0E-03	9.9E-04	1.1E-03
		TOTAL		1.90	0.00		3.85	0.96		1.86	7.69	0.19	0.81	0.04	1.6E-01		1.3E-02	3.1E-03				9.65

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.

(b) Emission factors from AP-42 Section 1.4, Updated 7/1998

(c) Emission factors from AP-42 Section 3.3, Updated 10/1996

(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

			Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
			Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
Chemical	CAS	POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
Lead						1.4E-05	4.2E-02	1.1E-02	5.0E-04	4.9E-04	2.0E-03	4.9E-05	2.1E-04	9.8E-06	4.3E-05							2.3E-03

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.
(b) Emission factors from AP-42 Section 1.4, Updated 7/1998
(c) Emission factors from AP-42 Section 3.3, Updated 10/1996
(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

South Shore Energy, LLC - Nemadji Trail Energy Center
Combined Cycle HAPs Emissions - New Emission Sources

Hours of Operation

Combustion Turbine Natural Gas Hours =	8,260	hours per year
Combustion Turbine Fuel Oil Hours =	500	hours per year
Duct Burner =	0	hours per year
Auxillary Boiler =	8,760	hours per year
Natural Gas Heater =	8,760	hours per year
Emergency Diesel Fire Pump =	500	hours per year
Emergency Diesel Generator =	500	hours per year

Total Facility: Hazardous Air Pollutants Emissions

HAP	Maximum Potential Emissions tpy
1st Maximum: Formaldehyde	3.31
2nd Maximum: Toluene	1.97
3rd Maximum: Xylene	0.97
All HAPs	9.82

Natural Gas Usage

	mmBtu/hr	mmCF/hr	
			1,020 MMBtu/MMcf
Combustion Turbine (Natural Gas) =	3,665	--	
Combustion Turbine (Fuel Oil) =	3,021	--	
Duct Burner =	1,006	0.987	
Auxillary Boiler =	100.0	0.098	
Natural Gas Heater =	20.0	0.020	2 Natural Gas Heaters
Emergency Diesel Fire Pump =	1.95	--	
Emergency Diesel Generator =	20.6	--	

				Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
Total		CAS		Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
tpy	Chemical		POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMcf	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
1.2367E-05	2-Methylnaphthalene	97-57-6	POM							2.4E-05	2.4E-05	0.0E+00	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.2E-05
9.2753E-07	3-Methylchloranthrene	56-49-5	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07							9.3E-07
8.2447E-06	7,12-Dimethylbenz(a)anthracene		POM							1.6E-05	1.6E-05	0.0E+00	1.6E-06	6.9E-06	3.1E-07	1.4E-06							8.2E-06
2.5663E-05	Acenaphthene	83-32-9	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.42E-06	2.8E-06	6.9E-07	4.68E-06	9.6E-05	2.4E-05	2.6E-05
5.0813E-05	Acenaphthylene	203-96-8	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	5.06E-06	9.9E-06	2.5E-06	9.23E-06	1.9E-04	4.7E-05	5.1E-05
0.60594777	Acetaldehyde	75-07-0		4.0E-05	1.5E-01	6.1E-01											7.67E-04	1.5E-03	3.7E-04	2.52E-05	5.2E-04	1.3E-04	6.1E-01
0.09695668	Acrolein	107-02-8		6.4E-06	2.3E-02	9.7E-02											9.25E-05	1.8E-04	4.5E-05	7.88E-06	1.6E-04	4.0E-05	9.7E-02
8.4675E-06	Anthracene	120-12-7	POM							2.4E-06	2.4E-06	0.0E+00	2.4E-07	1.0E-06	4.7E-08	2.1E-07	1.87E-06	3.6E-06	9.1E-07	1.23E-06	2.5E-05	6.3E-06	8.5E-06
0.00841054	Arsenic	7440-38-2					1.1E-05	3.3E-02	8.3E-03	2.0E-04	2.0E-04	0.0E+00	2.0E-05	8.6E-05	3.9E-06	1.7E-05							8.4E-03
4.9421E-06	Benz(a)anthracene	56-55-3	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.68E-06	3.3E-06	8.2E-07	6.22E-07	1.3E-05	3.2E-06	4.9E-06
0.2286944	Benzene	71-43-2		1.2E-05	4.4E-02	1.8E-01	5.5E-05	1.7E-01	4.2E-02	2.1E-03	2.1E-03	0.0E+00	2.1E-04	9.0E-04	4.1E-05	1.8E-04	9.33E-04	1.8E-03	4.5E-04	7.76E-04	1.6E-02	4.0E-03	2.3E-01
2.0303E-06	Benzo(a)pyrene	50-32-8	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	1.88E-07	3.7E-07	9.2E-08	2.57E-07	5.3E-06	1.3E-06	2.0E-06
6.6785E-06	Benzo(b)fluoranthene	205-99-2	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	9.91E-08	1.9E-07	4.8E-08	1.11E-06	2.3E-05	5.7E-06	6.7E-06
3.7132E-06	Benzo(g,h,I)perylene	191-24-2	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	4.89E-07	9.5E-07	2.4E-07	5.56E-07	1.1E-05	2.9E-06	3.7E-06
2.1231E-06	Benzo(k)fluoranthene	205-82-3	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	1.55E-07	3.0E-07	7.6E-08	2.18E-07	4.5E-06	1.1E-06	2.1E-06
0.0002403	Beryllium	7440-41-7					3.1E-07	9.4E-04	2.3E-04	1.2E-05	1.2E-05	0.0E+00	1.2E-06	5.2E-06	2.4E-07	1.0E-06							2.4E-04
0.0186112	1,3-Butadiene	106-99-0		4.3E-07	1.6E-03	6.5E-03	1.6E-05	4.8E-02	1.2E-02								3.91E-05	7.6E-05	1.9E-05				1.9E-02
0.00419191	Cadmium	7440-43-7					4.8E-06	1.5E-02	3.6E-03	1.1E-03	1.1E-03	0.0E+00	1.1E-04	4.7E-04	2.2E-05	9.4E-05							4.2E-03
0.0090289	Chromium	7440-47-3					1.1E-05	3.3E-02	8.3E-03	1.4E-03	1.4E-03	0.0E+00	1.4E-04	6.0E-04	2.7E-05	1.2E-04							9.0E-03
8.96E-06	Chrysene	218-01-9	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.53E-07	6.9E-07	1.7E-07	1.53E-06	3.1E-05	7.9E-06	9.0E-06
4.3285E-05	Cobalt	7440-48-4								8.4E-05	8.3E-05	0.0E+00	8.2E-06	3.6E-05	1.6E-06	7.2E-06							4.3E-05
2.6801E-06	Dibenzo(a,h)anthracene	53-70-3	POM							1.2E-06	1.2E-06	0.0E+00	1.2E-07	5.2E-07	2.4E-08	1.0E-07	5.83E-07	1.1E-06	2.8E-07	3.46E-07	7.1E-06	1.8E-06	2.7E-06
0.00061835	Dichlorobenzene	25321-22-6								1.2E-03	1.2E-03	0.0E+00	1.2E-04	5.2E-04	2.4E-05	1.0E-04							6.2E-04
0.48435551	Ethyl benzene	100-41-4		3.2E-05	1.2E-01	4.8E-01																	4.8E-01
2.596E-05	Fluoranthene	206-44-0	POM							3.0E-06	3.0E-06	0.0E+00	2.9E-07	1.3E-06	5.9E-08	2.6E-07	7.61E-06	1.5E-05	3.7E-06	4.03E-06	8.3E-05	2.1E-05	2.6E-05
8.1438E-05	Fluorene	86-73-7	POM							2.8E-06	2.8E-06	0.0E+00	2.7E-07	1.2E-06	5.5E-08	2.4E-07	2.92E-05	5.7E-05	1.4E-05	1.28E-05	2.6E-04	6.6E-05	8.1E-05
3.30858509	Formaldehyde	50-00-0		2.0E-04	7.4E-01	3.1E+00	2.8E-04	8.5E-01	2.1E-01	7.5E-02	7.4E-02	0.0E+00	7.4E-03	3.2E-02	1.5E-03	6.4E-03	1.18E-03	2.3E-03	5.8E-04	7.89E-05	1.6E-03	4.1E-04	3.3E+00
0.92752941	Hexane	110-54-3								1.8E+00	1.8E+00	0.0E+00	1.8E-01	7.7E-01	3.5E-02	1.5E-01							9.3E-01
3.2373E-06	Indeno(1,2,3-cd)pyrene	193-39-5	POM							1.8E-06	1.8E-06	0.0E+00	1.8E-07	7.7E-07	3.5E-08	1.5E-07	3.75E-07	7.3E-07	1.8E-07	4.14E-07	8.5E-06	2.1E-06	3.2E-06
0.59682427	Manganese	7439-96-5					7.9E-04	2.4E+00	6.0E-01	3.8E-04	3.7E-04	0.0E+00	3.7E-05	1.6E-04	7.5E-06	3.3E-05							6.0E-01
0.00104025	Mercury	7439-97-6					1.2E-06	3.6E-03	9.1E-04	2.6E-04	2.6E-04	0.0E+00	2.5E-05	1.1E-04	5.1E-06	2.2E-05							1.0E-03
0.04713339	Naphthalene	91-20-3		1.3E-06	4.8E-03	2.0E-02	3.5E-05	1.1E-01	2.6E-02	6.1E-04	6.0E-04	0.0E+00	6.0E-05	2.6E-04	1.2E-05	5.2E-05	8.48E-05	1.7E-04	4.1E-05	1.30E-04	2.7E-03	6.7E-04	4.7E-02
0.00455616	Nickel	7440-02-0					4.6E-06	1.4E-02	3.5E-03	2.1E-03	2.1E-03	0.0E+00	2.1E-04	9.0E-04	4.1E-05	1.8E-04							4.6E-03
0.06350848	PAH			2.2E-06	8.1E-03	3.3E-02	4.0E-05	1.2E-01	3.0E-02														6.4E-02
0.0002327	Phenanathrene	85-01-8	POM							1.7E-05	1.7E-05	0.0E+00	1.7E-06	7.3E-06	3.3E-07	1.5E-06	2.94E-05	5.7E-05	1.4E-05	4.08E-05	8.4E-04	2.1E-04	2.3E-04
0.01559138	Propylene																2.58E-03	5.0E-03	1.3E-03	2.79E-03	5.7E-02	1.4E-02	1.6E-02
0.43894718	Proplylene Oxide	75-56-9		2.9E-05	1.1E-01	4.4E-01																	4.4E-01
2.3967E-05	Pyrene	129-00-0	POM							5.0E-06	4.9E-06	0.0E+00	4.9E-07	2.1E-06	9.8E-08	4.3E-07	4.78E-06	9.3E-06	2.3E-06	3.71E-06	7.6E-05	1.9E-05	2.4E-05
0.01889301	Selenium	7782-49-2					2.5E-05	7.6E-02	1.9E-02	2.4E-05	2.4E-05	0.0E+00	2.4E-06	1.0E-05	4.7E-07	2.1E-06							1.9E-02
1.9710893	Toluene	108-88-3		1.3E-04	4.8E-01	2.0E+00				3.4E-03	3.4E-03	0.0E+00	3.3E-04	1.5E-03	6.7E-05	2.9E-04	4.09E-04	8.0E-04	2.0E-04	2.81E-04	5.8E-03	1.4E-03	2.0E+00
0.9698415	Xylene	1330-20-7		6.4E-05	2.3E-01	9.7E-01											2.85E-04	5.6E-04	1.4E-04	1.93E-04	4.0E-03	9.9E-04	9.7E-01
			TOTAL		1.90	7.86		3.85	0.96		1.86	0.00	0.19	0.81	0.04	1.6E-01		1.3E-02	3.1E-03				9.82

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.
(b) Emission factors from AP-42 Section 1.4, Updated 7/1998
(c) Emission factors from AP-42 Section 3.3, Updated 10/1996
(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

				Natural Gas - Internal Combustion			Fuel Oil - Internal Combustion			Natural Gas- External Combustion							Fuel Oil						
Total				Combustion Turbine[a]			Combustion Turbine[a]			Emission Factor	Duct Burner[b]		Auxillary Boiler[b]		Natural Gas Heaters[b]		Emission Factor	Emergency Diesel Fire Pump[c]		Emission Factor	Emergency Diesel Generator[d]		Total
tpy	Chemical	CAS	POM?	lb/MMBtu	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/mmCF	lb/hr	tpy	lb/MMBtu	lb/hr	tpy	tpy
0.00025765	Lead						1.4E-05	4.2E-02	1.1E-02	5.0E-04	4.9E-04	0.0E+00	4.9E-05	2.1E-04	9.8E-06	4.3E-05							2.6E-04

(a) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.
(b) Emission factors from AP-42 Section 1.4, Updated 7/1998
(c) Emission factors from AP-42 Section 3.3, Updated 10/1996
(d) Emission factors from AP-42 Section 3.4, Updated 10/1996

1/28/2022 Revision

South Shore Energy, LLC - Nemadji Trail Energy Center
Q/D Analysis for Federal Class I Areas

Nemadji River Site

Class I Area	D (km)	Fuel Oil Duct Firing Operation Q/D (Based on max 24-hr for 365 days per year)	Natural Gas Duct Firing Operation Q/D (Based on max 24-hr for 365 days per year)
Rainbow Lake Wilderness	60	9.9	7.3
Boundary Waters Canoe Area Wilderness	126	4.7	3.5
Voyageurs National Park	182	3.3	2.4
Isle Royale National Park	237	2.5	1.9
Forest County Potawatomi Community	261	2.3	1.7

Pollutant	Fuel Oil Duct Firing 24-hr Max Emissions: Max Emissions in 24-hr period (lb/24-hr period)[a]	Fuel Oil Duct Firing 24-hr Max Emissions: Max 24-hour for 365 Days Per Year (tpy)	Natural Gas Duct firing 24-hr Max Emissions: Max Emissions in 24-hr period (lb/24-hr period)[a]	Natural Gas Duct firing 24-hr Max Emissions: Max 24-hour for 365 Days Per Year (tpy)
NO_x	1,569.0	286.3	1,109.3	202.4
PM_{10}	1,322.3	241.3	901.9	164.6
SO2	145.8	26.6	156.1	28.5
H_2SO_4	222.9	40.7	236.8	43.2
	$Q_{\text{duct firing fuel oil}}$=	594.9	$Q_{\text{natural gas duct firing}}$=	438.7

Scenario 1: Worst-Case Fuel Oil Turbine Operation With Duct firing

Pollutant	Turbine Fuel Oil Duct Firing (lb/24-hour period)[a]	Auxiliary Boiler (lb/24-hour period)[b]	Haul Road Fugitives ~~Cooling Tower~~ (lb/24-hour period)	Natural Gas Heater #1 or #2 (lb/24-hour period)[c]
NO_x	1,555.0	2.20	0.00	11.76
PM_{10}	1,308.3	1.49	10.74	1.79
SO2	145.6	0.12	0.00	0.14
H_2SO_4	222.8	0.02	0.00	0.02

(a) Turbine NOx emissions will be monitored via NOx CEMs and will not exceed 1,555 lb/24-hr while duct firing and combusting fuel oil. In addition, fuel oil is limited to fuel consumption equivalent of 500 hours per year, however emissions are based on 8,760 hours per year.
(b) The auxiliary boiler will operate maximum 2 hours in a 24-hr period when fuel oil duct firing occurs
(c) One natural gas heater will operate at a time (one is back-up)

Scenario 2: Worst-Case Natural Gas Turbine Operation With Duct firing

Pollutant	Turbine Natural Gas Duct Firing (lb/24-hour period)[a]	Auxiliary Boiler (lb/24-hour period)	Haul Road Fugitives ~~Cooling Tower~~ (lb/24-hour period)	Natural Gas Heater #1 or #2 (lb/24-hour period)[b]
NO_x	1,071.1	26.40	0.00	11.76
PM_{10}	871.5	17.88	10.74	1.79
SO2	154.5	1.41	0.00	0.14
H_2SO_4	236.6	0.22	0.00	0.02

(a) Includes one start-up per day.
(b) One natural gas heater will operate at a time (one is back-up)

lb/hr emissions

Pollutant	Turbine Fuel Oil Duct Firing (lb/hr)	Turbine Natural Gas Duct Firing (lb/hr)	Auxiliary Boiler (lb/hr)	Haul Road Fugitives (lb/hr)	Natural Gas Heater (lb/hr)
NO_x	--[a]	33.5	1.1	0.00	0.5
PM_{10}	54.5	36.3	0.7	0.45	0.07
SO2	6.1	6.4	0.06	0.00	5.9E-03
H_2SO_4	9.3	9.9	9.0E-03	0.00	9.0E-04

(a) 24-hr emissions will be less than 1,555 lbs for the combustion turbine while combusting fuel oil and duct firing.

lb/start-up emissions

Pollutant	Fuel Oil Start-up Emissions (lb/cold start)[a,b]	Natural Gas Start-up Emissions (lb/cold start)[a,b]
NO_x	860.0	335.0
PM_{10}	78.9	43.6
SO2	9.2	10.2
H_2SO_4	14.0	15.6

(a) Start-up emissions based on vendor load and start-up profiles
(b) Start-up emissions are 2 hours.

South Shore Energy, LLC - Nemadji Trail Energy Center
NR 445 Analysis

Pollutant	Stack Height Class	$E_{Unobstructed}$		4x($E_{Obstructed}$ + $E_{Fugitive}$)		E_{Total}		NR 445 Thresholds		In compliance with NR 445 Thresholds?	
		lb/hr	lb/yr	avg. lb/hr	lb/yr	avg. lb/hr	lb/yr	1-hr/24-hr avg.	Annual	1-hr/24-hr avg.	Annual
Benzene (71-43-2)	<25	--	--	--	141	--	141	--	228	--	Yes
	25<40	--	--	--	333	--	333	--	936	--	Yes
Ethylbenzene (100-41-4)	<25	--	--	0.018	124	0.018	124	23.3	177,688	Yes	Yes
	25<40	--	--	0.7	333	0.7	333	90.6	730,000	Yes	Yes
Hexane (110-54-3)	<25	--	--	0.034	263	0.034	263	9.47	35,538	Yes	Yes
	25<40	--	--	0.7	333	0.7	333	36.8	146,000	Yes	Yes
Toluene (108-88-3)	<25	--	--	0.034	263	0.034	263	10.1	17,075	Yes	Yes
	25<40	--	--	0.7	333	0.7	333	39.3	292,000	Yes	Yes
Xylene (1330-20-7)	<25	--	--	0.060	--	0.060	--	23.3	--	Yes	--
	25<40	--	--	0.7	--	0.7	--	90.6	--	Yes	--
Ammonia (7664-41-7)	>75	62	543,120	--	--	62	543,120	28.2	612,587	No	Yes

Sources:
WDNR Memo. Chapter NR 445 Compliance Demonstration Method for Non-exempt Potential Emissions from Non-vertical or Obstructed Stacks and Non-exempt Potential Fugitive Emissions. October 20, 2005.
NR 445, Wis. Adm. Code - Control of Hazardous Pollutants

$E_{Fugitive}$ Emissions from Piping Fugitives Breakdown

	VOC (lb/hr)	VOC (lb/yr)
	lb/hr	lb/yr
Natural Gas	0.64	5,609
Fuel Oil	1.73	15,153

Pollutant	$E_{Fugitive}$			$E_{Fugitive}$			Total $E_{Fugitive}$		4x ($E_{Fugitive}$)	
	Natural Gas			Fuel Oil			Fuel Oil + Natural Gas		Fuel Oil + Natural Gas	
	wt%	lb/hr	lb/yr	wt%	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr
Benzene (71-43-2)	0.08%	0.00051	4.5	0.2%	0.003	30	0.004	35	0.016	139
Ethylbenzene (100-41-4)				0.2%	0.003	30	0.003	30.306	0.014	121
Hexane (110-54-3)	0.08%	0.00051	4.5	0.4%	0.01	60.61	0.01	65	0.030	260
Toluene (108-88-3)	0.08%	0.00051	4.5	0.4%	0.01	61	0.01	65	0.030	260
Xylene (1330-20-7)				0.8%	0.01	121	0.01	121	0.055	485

EPA Storage Tanks Program Calculations

TANKS 4.P.P
issions Report - Detail ForP at P
Tank InPentification anP Physical CharacteristicsP

IPentificationP

User IdenF on:F	NTEC Turb ne D esel TFnkF
CFy:F	DuluFhF
SF e:F	W sFons nF
CompFny:F	NTECF
Type oFTFnk:F	VerF l F xed RooFTFnkF
DesFr pFon:F	180,000 gFllon bF kup Fuel F nk For Furb nesF

Tank DiP ensionsP

Shell He ghF(F):F	30.00F
DF meFer (F):F	33.00F
L qu d He ghF(F) :F	28.14F
Avg. L qu d He ghF(F):F	14.07F
Volume (gFllons):F	180,042.51F
Turnovers:F	59.94F
NeFThroughpuF(gFl/yr):F	10,791,747.84F
Is TFnk HeF ed (y/n):F	NF

aint CharacteristicsP

Shell Color/ShFde:F	WhFe/WhFeF
Shell CondF onF	GoodF
RooFColor/ShFde:F	WhFe/WhFeF
RooFCondF on:F	GoodF

Roof CharacteristicsP

Type:F	ConeF
He ghF(F)F	5.00F
Slope (F/F) (Cone RooF)F	0.30F

Breather Vent SettingsP

VF uum SeF ngs (ps g):F	-0.03F
Pressure SeF ngs (ps g)F	0.03F

MeFerologF l DF used n Em ss ons CFl ulF ons: DuluFh, M nnesoF (Avg A mospherF Pressure = 13.98 psF)F

TANKS 4.P.P
issions Report - Detail ForP at P
LiquiP Contents of Storage TankP

NTPC Turbine Diesel Tank - Vertical FixeP Roof TankP
Duluth, WisconsinP

M xFure/ComponenF	Mon hF	DF ly L qu d SurF.F TemperF ure (deg F)F Avg.F	M n.F	MFx.F	L qu dF BulkF TempF (deg F)F	VFpor Pressure (psF)F Avg.F	M n.F	MFx.F	VFporF Mol.F We gh .F	L qu dF MFssF rF .F	VFporF MFssF rF .F	Mol.F We ghF	BFs s For VFpor PressureF CFlFulF onsF
D sFlIF e uel o l no. 2F	AllF	40.03F	35.22F	44.84F	38.46F	0.0031F	0.0031F	0.0038F	130.0000F			188.00F	OpFon 1: VP40 = .0031 VP50 = .0045F

TANKS 4.P.P
issions Report - Detail ForP at P
Detail Calculations (AP-42)P

NTPC Turbine Diesel Tank - Vertical FixeP Roof TankP
Duluth, WisconsinP

AnnuFl Em ss on CFlF ulF onsF	
SF nd ng Losses (lb):F	14.1127F
VFpor SpF e Volume (Fu F):F	15,050.4043F
VFpor DensFy (lb/Fu F):F	0.0001F
VFpor SpF e ExpFns on F or:F	0.0342F
Ven ed VFpor SF urF on F or:F	0.9971F
TFnk VFpor SpF e Volume:F	
VFpor SpF e Volume (Fu F):F	15,050.4043F
TFnk DF me er (F):F	33.0000F
VFpor SpF e OuF ge (F):F	17.5967F
TFnk Shell He gh (F):F	30.0000F
AverFge L qu d He gh (F):F	14.0700F
Roo OuF ge (F):F	1.6667F
Roo OuF ge (Cone Roo)F	
Roo OuF ge (F):F	1.6667F
Roo He gh (F):F	5.0000F
Roo Slope (F/F):F	0.3000F
Shell RFd us (F):F	16.5000F
VFpor DensFyF	
VFpor DensFy (lb/Fu F):F	0.0001F
VFpor MoleFulFr We gh (lb/lb-mole):F	130.0000F
VFpor Pressure F DF ly AverFge L qu dF SurF e TemperF ure (psF):F	0.0031F
DF ly Avg. L qu d SurF e Temp. (deg. R):F	499.7017F
DF ly AverFge Amb en Temp. (deg. F):F	38.4417F
IdeFl GFs ConsF n RF (psF FuF / (lb-mol-deg R)):F	10.731F
L qu d Bulk TemperF ure (deg. R):F	498.1317F
TFnk PF n SolFr AbsorpF nFe (Shell):F	0.1700F
TFnk PF n SolFr AbsorpF nFe (Roo):F	0.1700F
DF ly ToF l SolFr InsulF onF F or (B u/sqF dFy):F	1,175.5647F
VFpor SpF e ExpFns on F orF	
VFpor SpF e ExpFns on F or:F	0.0342F
DF ly VFpor TemperF ure RFnge (deg. R):F	19.2277F
DF ly VFpor Pressure RFnge (psF):F	0.0007F
BreF her Ven Press. SeF ng RFnge(psF):F	0.0600F
VFpor Pressure F DF ly AverFge L qu dF SurF e TemperF ure (psF):F	0.0031F
VFpor Pressure F DF ly M n mum L qu dF SurF e TemperF ure (psF):F	0.0031F
VFpor Pressure F DF ly MFx mum L qu dF SurF e TemperF ure (psF):F	0.0038F
DF ly Avg. L qu d SurF e Temp. (deg R):F	499.7017F
DF ly M n. L qu d SurF e Temp. (deg R):F	494.8947F
DF ly MFx. L qu d SurF e Temp. (deg R):F	504.5086F
DF ly Amb en Temp. RFnge (deg. R):F	18.9333F
Ven ed VFpor SF urF on F orF	
Ven ed VFpor SF urF on F or:F	0.9971F
VFpor Pressure F DF ly AverFge L qu d:F SurF e TemperF ure (psF):F	0.0031F
VFpor SpF e OuF ge (F):F	17.5967F
Work ng Losses (lb):F	69.1835F
VFpor MoleFulFr We gh (lb/lb-mole):F	130.0000F
VFpor Pressure F DF ly AverFge L qu dF SurF e TemperF ure (psF):F	0.0031F
AnnuFl Ne Throughpu (gFl/yr.):F	10,791,747.8413F
AnnuFl Turnovers:F	59.9400F
Turnover F or:F	0.6672F
MFx mum L qu d Volume (gFl):F	180,042.5065F
MFx mum L qu d He gh (F):F	28.1400F
TFnk DF me er (F):F	33.0000F
Work ng Loss ProduF F or:F	1.0000F
ToF l Losses (lb):F	83.2962F

TANKS 4.P.P
issions Report - Detail ForP at P
InPiviPual Tank P ission TotalsP

issions Report for: Annual P

NTPC Turbine Diesel Tank - Vertical FixeP Roof TankP
Duluth, WisconsinP

	Losses(lbs)F		
ComponenF͡sF	Work ng LossF	BreF h ng LossF	ToF l Em ss onsF
D sFllF e uel o l no. 2F	69.18F	14.11F	83.30F

TANKS 4.P.P
issions Report - Detail ForP at P
Tank InPentification anP Physical CharacteristicsP

IPentificationP

User IdenD on:D	NTEC F re Pump TDnkD
CDy:D	Super orD
SD e:D	W sDons nD
CompDny:D	NTECD
Type o TDnk:D	Hor zonD l TDnkD
esDr pDon:D	350 gDllon d esel DnkD

Tank DiP ensionsP

Shell Leng h (D):D	5.00D
me er (D):D	3.45D
Volume (gDllons):D	350.00D
Turnovers:D	20.83D
Ne Throughpu (gDl/yr):D	7,291.55D
Is TDnk HeD ed (y/n):D	ND
Is TDnk Underground (y/n):D	ND

aint CharacteristicsP

Shell Color/ShDde:D	WhDe/WhDeD
Shell CondDonD	GoodD

Breather Vent SettingsP

VD uum SeDngs (ps g):D	-0.03D
Pressure SeDngs (ps g)D	0.03D

Me erologD l D used n Em ss ons CDl ulD ons: Dulu h, M nnesoD (Avg A mospherD Pressure = 13.98 psD)D

TANKS 4.P.P
issions Report - Detail ForP at P
LiquiP Contents of Storage TankP

NTPC Fire PuP p Tank - Horizontal TankP
Superior, WisconsinP

M x ure/ComponenD	Mon hD	ly L qu d Sur .D TemperDure (deg F)D Avg.D	M n.D	M x.D	L qu dD BulkD TempD (deg F)D	V por Pressure (psD)D Avg.D	M n.D	M x.D	V porD Mol.D We gh .D	L qu dD M ssD FrD .D	V porD M ssD FrD .D	Mol.D We ghD	B s s or VDpor PressureD C l ulD onsD
s llDe uel o l no. 2	AllD	40.03D	35.22	44.84D	38.46D	0.0031D	0.0031D	0.0038D	130.0000D			188.00D	OpDon 1: VP40 = .0031 VP50 = .0045D

TANKS 4.P.P
issions Report - Detail ForP at P
Detail Calculations (AP-42)P

NTPC Fire PuP p Tank - Horizontal TankP
Superior, WisconsinP

AnnuDl Em ss on CDlD ulD onsD	
SDnd ng Losses (lb):D	0.0280D
VDpor SpD e Volume (Du D):D	29.8059D
VDpor DensDy (lb/Du D):D	0.0001D
VDpor SpD e ExpDns on FD or:D	0.0342
Ven ed VDpor SDurD on FD or:D	0.9997D
TDnk VDpor SpD e Volume:D	
VDpor SpD e Volume (Du D):D	29.8059D
TDnk D me er (D):D	3.4520D
EDeD ve D me er (D):D	4.6891D
VDpor SpD e OuD ge (D):D	1.7260D
TDnk Shell Leng h (D):D	5.0000D
VDpor DensDyD	
VDpor DensDy (lb/Du D):D	0.0001D
VDpor MoleDulDr We gh (lb/lb-mole):D	130.0000D
VDpor Pressure D D ly AverDge L qu dD	
SurD e TemperDure (psD):D	0.0031D
D ly Avg. L qu d SurD e Temp. (deg. R):D	499.7017D
D ly AverDge Amb en Temp. (deg. F):D	38.4417D
IdeDl GDs ConsDn RD	
(psD DuD / (lb-mol-deg R)):D	10.731D
L qu d Bulk TemperDure (deg. R):D	498.1317D
TDnk PDn SolDr AbsorpDn e (Shell):D	0.1700D
D ly ToDl SolDr InsulD onD	
FD or (B u/sqD dDy):D	1,175.5647D
V por SpD e ExpDns on FD orD	
VDpor SpD e ExpDns on FD or:D	0.0342
D ly VDpor TemperDure RDnge (deg. R):D	19.2277D
D ly VDpor Pressure RDnge (psD):D	0.0007D
BreDher Ven Press. SeDng RDnge(psD):D	0.0600D
VDpor Pressure D D ly AverDge L qu dD	
SurD e TemperDure (psD):D	0.0031D
VDpor Pressure D D ly M n mum L qu dD	
SurD e TemperDure (psD):D	0.0031D
VDpor Pressure D D ly MDx mum L qu dD	
SurD e TemperDure (psD):D	0.0038D
D ly Avg. L qu d SurD e Temp. (deg R):D	499.7017D
D ly M n. L qu d SurD e Temp. (deg R):D	494.8947D
D ly MDx. L qu d SurD e Temp. (deg R):D	504.5086D
D ly Amb en Temp. RDnge (deg. R):D	18.9333D
Ven ed VDpor SDurD on FD orD	
Ven ed VDpor SDurD on FD or:D	0.9997D
VDpor Pressure D D ly AverDge L qu d:D	
SurD e TemperDure (psD):D	0.0031D
VDpor SpD e OuD ge (D):D	1.7260D
Work ng Losses (lb):D	0.0701D
VDpor MoleDulDr We gh (lb/lb-mole):D	130.0000D
VDpor Pressure D D ly AverDge L qu dD	
SurD e TemperDure (psD):D	0.0031D
AnnuDl Ne Throughpu (gDl/yr.):D	7,291.5500D
AnnuDl Turnovers:D	20.8330D
Turnover FD or:D	1.0000D
TDnk D me er (D):D	3.4520D
Work ng Loss ProduD FD or:D	1.0000D
ToDl Losses (lb):D	0.0981D

TANKS 4.P.P
issions Report - Detail ForP at P
InPiviPual Tank P ission TotalsP

issions Report for: Annual P

NTPC Fire PuP p Tank - Horizontal TankP
Superior, WisconsinP

	Losses(lbs)D		
Componen sD	Work ng LossD	BreDh ng LossD	ToDl Em ss onsD
sDlDe uel o l no. 2	0.07D	0.03D	0.10D

TANKS 4.P.P
issions Report - Detail ForP at P
Tank InPentification anP Physical CharacteristicsP

IPentificationP

User Iden1 on:1	NTEC Gen T1nk1
C1y:1	Super or1
S1 e:1	W s1ons n1
Comp1ny:1	NTEC1
Type o1T1nk:1	Hor zon1 l T1nk1
Des1r p1on:1	,700 g1llon d esel 1 nk1

Tank DiP ensionsP

Shell Leng1h (1):1	8.041
D1 me1er (1):1	6.001
Volume (g1llons):1	,700.001
Turnovers:1	20.801
Ne1Throughpu1(g1l/yr):1	35,360.001
Is T1nk He1 ed (y/n):1	N1
Is T1nk Underground (y/n):1	N1

aint CharacteristicsP

Shell Color/Sh1de:1	Wh1e/Wh1e1
Shell Cond1 on1	Good1

Breather Vent SettingsP

V uum Se1 ngs (ps g):1	-0.031
Pressure Se1 ngs (ps g)1	0.031

Me1erolog1 l D1 used n Em ss ons C1l ul1 ons: Dulu1h, M nneso1 (Avg A mospher1 Pressure = 13.98 ps1)1

TANKS 4.P.P
issions Report - Detail ForP at P
LiquiP Contents of Storage TankP

NTPC Gen Tank - Horizontal TankP
Superior, WisconsinP

M x1ure/Componen1	Mon h1	D1 ly L qu d Sur1.1 Temper1 ure (deg F)1 Avg.1	M n.1	M x.1	L qu d1 Bulk1 Temp1 (deg F)1	V por Pressure (ps1)1 Avg.1	M n.1	M x.1	V por1 Mol.1 We gh11	L qu d1 M ss1 Fr1 .1	V por1 M ss1 Fr1 .1	Mol.1 We gh1	B s s 1or V por Pressure1 C l ul1 ons1
D s1ll1 e uel o l no. 21	All1	40.031	35.221	44.841	38.461	0.0031	0.0031	0.00381	30.00001			88.001	Op1on 1: VP40 = .0031 VP50 = .00451

TANKS 4.P.P

issions Report - Detail ForP at P

Detail Calculations (AP-42)P

NTPC Gen Tank - Horizontal TankP
Superior, WisconsinP

Annu1l Em ss on C1l1 ul1 ons1	
S1 nd ng Losses (lb):1	0.1361
V por Sp1 e Volume (1u 1):1	44.75741
V por Dens1y (lb/1u 1):1	0.0001
V por Sp1 e Exp1ns on F1 or:1	0.03421
Ven ed V por S1 ur1 on F1 or:1	0.99951
T1nk V por Sp1 e Volume:1	
V por Sp1 e Volume (1u 1):1	44.75741
T1nk D1 me er (1):1	6.00001
E1e1 ve D1 me er (1):1	7.83821
V por Sp1 e Ou1 ge (1):1	3.00001
T1nk Shell Leng h (1):1	8.03801
V por Dens1y1	
V por Dens1y (lb/1u 1):1	0.0001
V por Mole1ul1r We gh (lb/lb-mole):1	30.00001
V por Pressure 1 D1 ly Aver1ge L qu d1 Sur1 e Temper1 ure (ps1):1	0.0031
D1 ly Avg. L qu d Sur1 e Temp. (deg. R):1	499.70171
D1 ly Aver1ge Amb en Temp. (deg. F):1	38.44171
Ide1l G1s Cons1 n R1 (ps1 1u1 / (lb-mol-deg R)):1	0.731
L qu d Bulk Temper1 ure (deg. R):1	498.13171
T1nk P1 n Sol1r Absorp1 n1e (Shell):1	0.17001
D1 ly To1 l Sol1r Insul1 on1 F1 or (B u/sq1 d1y):1	,175.56471
V por Sp1 e Exp1ns on F1 or1	
V por Sp1 e Exp1ns on F1 or:1	0.03421
D1 ly V por Temper1 ure R1nge (deg. R):1	9.22771
D1 ly V por Pressure R1nge (ps1):1	0.00071
Bre1 her Ven Press. Se1 ng R1nge(ps1):1	0.06001
V por Pressure 1 D1 ly Aver1ge L qu d1 Sur1 e Temper1 ure (ps1):1	0.0031
V por Pressure 1 D1 ly M n mum L qu d1 Sur1 e Temper1 ure (ps1):1	0.0031
V por Pressure 1 D1 ly M1x mum L qu d1 Sur1 e Temper1 ure (ps1):1	0.00381
D1 ly Avg. L qu d Sur1 e Temp. (deg R):1	499.70171
D1 ly M n. L qu d Sur1 e Temp. (deg R):1	494.89471
D1 ly M1x. L qu d Sur1 e Temp. (deg R):1	504.50861
D1 ly Amb en Temp. R1nge (deg. R):1	8.93331
Ven ed V por S1 ur1 on F1 or1	
Ven ed V por S1 ur1 on F1 or:1	0.99951
V por Pressure 1 D1 ly Aver1ge L qu d:1 Sur1 e Temper1 ure (ps1):1	0.0031
V por Sp1 e Ou1 ge (1):1	3.00001
Work ng Losses (lb):1	0.33981
V por Mole1ul1r We gh (lb/lb-mole):1	30.00001
V por Pressure 1 D1 ly Aver1ge L qu d1 Sur1 e Temper1 ure (ps1):1	0.0031
Annu1l Ne Throughpu (g1l/yr.):1	35,360.00001
Annu1l Turnovers:1	20.80001
Turnover F1 or:1	.00001
T1nk D1 me er (1):1	6.00001
Work ng Loss Produ1 F1 or:1	.00001
To1 l Losses (lb):1	0.47581

TANKS 4.P.P
issions Report - Detail ForP at P
InPiviPual Tank P ission TotalsP

issions Report for: Annual P

NTPC Gen Tank - Horizontal TankP
Superior, WisconsinP

	Losses(lbs)1		
Componen1s1	Work ng Loss1	Bre1 h ng Loss1	To1 l Em ss ons1
D s1ll1 e 1uel o l no. 21	0.341	0.141	0.481

APPENDIX D – RBLC TABLES

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
			Nitrogen Oxides							
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	160	lb/hr	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	160	lb/hr	BACT	
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	SCR/DLN	0.034	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	SCR/DLN	0.082	lb/MMBtu	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP	0.190	lb/MMBtu	BACT	
CA-1178	APPLIED ENERGY LLC	APPLIED ENERGY LLC	3/20/2009	2,234	MMBtu/hr	SCR	2.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	2.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	2.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	2.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	SCR/DLN	2.0	ppm	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	SCR/DLN	2.0	ppm	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	SCR/DLN	2.0	ppm	BACT	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	2,333	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	1,860	MMBtu/hr	SCR	2.0	ppm	BACT	GE 7241 FA CTG
FL-0337	POLK POWER STATION	TAMPA ELECTRIC COMPANY	10/14/2012	1,160	MW	SCR/DLN	2.0	ppm	BACT	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	SCR/DLN/WI	2.0	ppm	BACT	GE 7HA.02
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	SCR/LNB	2.0	ppm	BACT	Siemens SGT6-5000F
ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	2,375	MMBtu/hr	SCR/DLN/GCP	2.0	ppm	BACT	Siemens SGT6-5000F
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	SCR/DLN/GCP	2.0	ppm	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	SCR/DLN/GCP	2.0	ppm	BACT	SGT6-500FEE
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	SCR/DLN	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	1,882	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	SIEMENS V84.3A
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	SCR/DLN	2.0	ppm	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	SCR/DLN	2.0	ppm	BACT	Siemens SGT6-5000F5
OR-0048	CARTY PLANT	PORTLAND GENERAL ELECTRIC	12/29/2010	2,866	MMBtu/hr	SCR	2.0	ppm	BACT	
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	DLN/WI	2.0	ppm	BACT	Mitsubishi M501-GAC
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	10/10/2012	3,277	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	G or HA
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	472		SCR	2.0	ppm	BACT	
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	4/19/2016	1,339	MMBtu/hr	SCR/GCP	2.0	ppm	BACT	
TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	350	MW	SCR	2.0	ppm	BACT	GE 7FA, GE 7FB, AND SIEMENS SGT6-5000F.
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR POWER PARTNERS II LLC	6/22/2009	250	MW	SCR	2.0	ppm	BACT	GE 7FAS OR 250 MW MITSUBISHI 501GS
TX-0548	MADISON BELL ENERGY CENTER	MADISON BELL PARTNERS LP	8/18/2009	275	MW	SCR	2.0	ppm	BACT	GE PG7121(EA
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	SCR/DLN	2.0	ppm	BACT	GE 7FA
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	SCR	2.0	ppm	BACT	GE 7FA
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	7/16/2014	87	MW	SCR	2.0	ppm	BACT	
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	NRG TEXAS POWER	8/29/2014	225	MW	SCR/DLN	2.0	ppm	BACT	Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	2/7/2013	650	MW	SCR	2.0	ppm	BACT	GE 7FA.04; (2 Siemens SGT6-5000F(4; or (3 Siemens SGT6-5000F(5.
TX-0709	SAND HILL ENERGY CENTER	CITY OF AUSTIN	9/13/2013	174	MW	SCR	2.0	ppm	BACT	GE 7FA
TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	197	MW	SCR	2.0	ppm	BACT	GE 7FA.04
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	497	MW	SCR	2.0	ppm	BACT	MHI J model
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TENASKA BROWNSVILLE PARTNERS, LLC	4/29/2014	274	MW	SCR	2.0	ppm	BACT	
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	240	MW	SCR	2.0	ppm	BACT	Siemens Model F5 (SF5
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	SCR/OxCat	2.0	ppm	BACT	GE Model 7HA.02
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	SCR	2.0	ppm	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	SCR	2.0	ppm	BACT	Alstom GT36
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	SCR	2.0	ppm	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	SCR	2.0	ppm	BACT	Siemens or GE
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	426	MW	SCR/DLN	2.0	ppm	BACT	Siemens SGT6-5000F5
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	MHI M501 GAC
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	SCR/DLN	2.0	ppm	BACT	GE Frame 7FA.04
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	SCR/DLN	2.5	ppm	BACT	
GA-0138	LIVE OAKS POWER PLANT	LIVE OAKS COMPANY, LLC	4/8/2010	600	MW	SCR/DLN	2.5	ppm	BACT	SGT6-5000F.
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	SCR/LNB	3.0	ppm	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	SCR/DLN	3.0	ppm	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	SCR/DLN	3.0	ppm	BACT	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	SCR/DLN	3.0	ppm	BACT	
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	SCR/DLN	3.0	ppm	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	SCR/DLN	3.0	ppm	BACT	GE 7FA
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	SCR/LNB	4.0	ppm	BACT	
AK-0073	INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	12/20/2010	45	MW	SCR/DLN	5.0	ppm	BACT	
LA-0136	PLAQUEMINE COGENERATION FACILITY	THE DOW CHEMICAL COMPANY	7/23/2008	2,876	MMBtu/hr	SCR/DLN	5.0	ppm	BACT	GE FRAME 7 FA
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	607	MMBtu/hr	SCR/WI	5.0	ppm	BACT	
TX-0698	BAYPORT COMPLEX	AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	9/5/2013	90	MW	DLN, CLEC	5.0	ppm	BACT	GE 7EA
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	130	MW	LNB	9.0	ppm	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	SCR/DLN	15.0	ppm	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	SCR/DLN	15.0	ppm	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	SCR/LNB	78.4	tpy	BACT	
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	SCR	131.6	tpy	BACT	
Carbon Monoxide										
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	OxCat/GCP	0.003	lb/MMBtu	BACT	
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	OxCat	0.016	lb/MMBtu	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	OxCat/GCP	0.061	lb/MMBtu	BACT	
OK-0169	PSO COMANCHE POWER STATION	PUBLIC SERVICE COMPANY OF OKLAHOMA	10/8/2015	1,250	MMBtu/hr	DLN	0.079	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	OxCat	0.213	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	OxCat/GCP	0.382	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	OxCat/GCP	0.446	lb/MMBtu	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP	0.747	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	1.396	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	OxCat	1.700	lb/MMBtu	BACT	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,142	MMBtu/hr	OxCat	0.9	ppm	BACT	SIEMENS SGT6-5000F
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	OxCat	0.9	ppm	BACT	GE 7HA.01
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	OxCat	0.9	ppm	BACT	GE 7HA.01
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	OxCat	0.9	ppm	BACT	Mitsubishi M501JAC
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	OxCat/GCP/Fuel	0.9	ppm	BACT	Siemens F
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	OxCat	1.5	ppm	BACT	Never built. Proposed Model GE 7241 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	OxCat	1.5	ppm	BACT	Never built. Proposed Model GE 7241 FA

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	OxCat	1.5	ppm	BACT	Never built. In 2011, proposed turbines were GE. Currently proposed turbines are Siemens STG6-5000F
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	OxCat/GCP/Fuel	1.5	ppm	BACT	Siemens F
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	OxCat/GCP	1.5	ppm	BACT	MHI M501 GAC
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	254	MW	OxCat	1.8	ppm	BACT	MITSUBISHI MODEL M501G
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	2.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	OxCat	2.0	ppm	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	OxCat	2.0	ppm	BACT	
GA-0138	LIVE OAKS POWER PLANT	LIVE OAKS COMPANY, LLC	4/8/2010	600	MW	OxCat/GCP	2.0	ppm	BACT	SGT6-5000F.
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	OxCat	2.0	ppm	BACT	
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	OxCat	2.0	ppm	BACT	Siemens SGT6-5000F
ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	2,375	MMBtu/hr	OxCat, DLN, GCP	2.0	ppm	BACT	Siemens SGT6-5000F
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	OxCat	2.0	ppm	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	OxCat, DLN, GCP	2.0	ppm	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	OxCat, DLN, GCP	2.0	ppm	BACT	
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	OxCat/GCP	2.0	ppm	BACT	GE F class
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	OxCat/GCP	2.0	ppm	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	OxCat/GCP	2.0	ppm	BACT	SGT6-500FEE
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	OxCat	2.0	ppm	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	OxCat	2.0	ppm	BACT	
NJ-0074	WEST DEPTFORD ENERGY	LS POWER	5/6/2009	2,014	MMBtu/hr	OxCat	2.0	ppm	BACT	
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	7/25/2012	4,692	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	GE
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	7/25/2012	4,692	MMBtu/hr	OxCat/GCP/Fuel	2.0	ppm	BACT	GE 7FA
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	OxCat/GCP/Fuel	2.0	ppm	BACT	GE
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	OxCat	2.0	ppm	BACT	GE
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	OxCat/GCP/Fuel	2.0	ppm	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	OxCat, GCP, Fuel	2.0	ppm	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	OxCat, GCP, Fuel	2.0	ppm	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	OxCat, GCP, Fuel	2.0	ppm	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	OxCat/GCP	2.0	ppm	BACT	GE 7HA.02
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	OxCat/GCP	2.0	ppm	BACT	GE 7HA.02
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	OxCat/GCP	2.0	ppm	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	OxCat/GCP	2.0	ppm	BACT	Siemens SGT6-5000F5
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	10/10/2012	3,277	MMBtu/hr	OxCat	2.0	ppm	BACT	F Class
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	472		OxCat	2.0	ppm	BACT	
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	4/19/2016	1,339	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	
TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	350	MW	OxCat	2.0	ppm	BACT	GE 7FA, GE 7FB, AND SIEMENS SGT6-5000F.
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	1,350	MW	OxCat/GCP	2.0	ppm	BACT	SGT6-5000F CTGs or four GE Frame 7FA CTGs

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
TX-0689	CEDAR BAYOU ELECTRIC GENERATION STATION	NRG TEXAS POWER	8/29/2014	225	MW	OxCat	2.0	ppm	BACT	Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	2/7/2013	650	MW	OxCat	2.0	ppm	BACT	GE 7FA.04; (2 Siemens SGT6-5000F(4; or (3 Siemens SGT6-5000F(5.
TX-0709	SAND HILL ENERGY CENTER	CITY OF AUSTIN	9/13/2013	174	MW	OxCat	2.0	ppm	BACT	GE 7FA
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TENASKA BROWNSVILLE PARTNERS, LLC	4/29/2014	274	MW	OxCat	2.0	ppm	BACT	
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	OxCat	2.0	ppm	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	OxCat	2.0	ppm	BACT	Alstom GT36
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	426	MW	SCR/DLN	2.0	ppm	BACT	Siemens SGT6-5000F5
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	GE 7FA.04
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	3.0	ppm	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	3.0	ppm	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	OxCat	3.0	ppm	BACT	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	OxCat/GCP	3.0	ppm	BACT	
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	OxCat/GCP	3.3	ppm	BACT	Mitsubishi M501-GAC
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	OxCat	4.0	ppm	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	OxCat/GCP	4.0	ppm	BACT	GE 7FA
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP	4.0	ppm	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	GCP	4.0	ppm	BACT	Siemens/Westinghouse 501F
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	GCP	4.0	ppm	BACT	GE 7FA
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	7/16/2014	87	MW	OxCat	4.0	ppm	BACT	
TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	197	MW	OxCat	4.0	ppm	BACT	GE 7FA.04
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	497	MW	OxCat	4.0	ppm	BACT	MHI J model
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	240	MW	OxCat	4.0	ppm	BACT	Siemens Model F5 (SF5
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	SCR/OxCat	4.0	ppm	BACT	GE Model 7HA.02
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	OxCat	4.0	ppm	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	OxCat	4.0	ppm	BACT	Siemens or GE
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	GCP	4.3	ppm	BACT	GE 7HA.02
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	2,333	MMBtu/hr	GCP	6.0	ppm	BACT	
FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	1,860	MMBtu/hr	GCP	6.0	ppm	BACT	GE 7241 FA CTG
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	GCP/Fuel	6.0	ppm	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	GCP/Fuel	8.0	ppm	BACT	GE 7FA
OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	1,882	MMBtu/hr	GCP	8.0	ppm	BACT	SIEMENS V84.3A
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	9.0	ppm	BACT	
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	254	MW	OxCat	9.0	ppm	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP	10.0	ppm	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	10.5	ppm	BACT	
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR POWER PARTNERS II LLC	6/22/2009	250	MW	GCP	15.0	ppm	BACT	GE 7FAS OR 250 MW MITSUBISHI 501GS
TX-0698	BAYPORT COMPLEX	AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	9/5/2013	90	MW	DLN, CLEC	15.0	ppm	BACT	GE 7EA
TX-0727	CEDAR BAYOU ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	3/31/2015	187	MW	OxCat	15.0	ppm	BACT	
TX-0548	MADISON BELL ENERGY CENTER	MADISON BELL PARTNERS LP	8/18/2009	275	MW	GCP	17.5	ppm	BACT	GE PG7121(EA
LA-0136	PLAQUEMINE COGENERATION FACILITY	THE DOW CHEMICAL COMPANY	7/23/2008	2,876	MMBtu/hr	GCP	25.0	ppm	BACT	GE FRAME 7 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	11.8	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	13.5	lb/hr	BACT	GE 7FA
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	GCP/Fuel	18.0	lb/hr	BACT	GE 7FA
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens/Westinghouse 501F
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	250	MW	DLN	30.2	lb/hr	BACT	
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	43.0	lb/hr	BACT	GE Model 7HA.02
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0012	lb/MMBtu	BACT	
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0022	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0025	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0025	lb/MMBtu	BACT	Siemens
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	Fuel	0.0033	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0040	lb/MMBtu	BACT	
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	10/10/2012	3,277	MMBtu/hr	Fuel	0.0040	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	0.0042	lb/MMBtu	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	Fuel	0.0048	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0048	lb/MMBtu	BACT	Siemens
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	GCP/Fuel	0.0050	lb/MMBtu	BACT	GE F class
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	4/19/2016	1,339	MMBtu/hr	OxCat/GCP	0.0050	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP/Fuel	0.0070	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP/Fuel	0.0070	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT	
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	Fuel	0.0073	lb/MMBtu	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP/Fuel	0.0078	lb/MMBtu	BACT	
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	0.0100	lb/MMBtu	BACT	Siemens SGT6-5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	0.0100	lb/MMBtu	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP/Fuel	0.0115	lb/MMBtu	BACT	
DE-0024	GARRISON ENERGY CENTER	GARRISON ENERGY CENTER, LLC/ CALPINE CORPORATION	1/30/2013	2,260	MMBtu/hr	Fuel	0.0122	lb/MMBtu	BACT	
Volatile Organic Compounds										
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	CASTLETON COMMODITIES INTERNATIONAL (CCI) CORPU	6/19/2015	37	MMBtu/hr	GCP/Fuel	0.005	LB/100 SCF	BACT	
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	GCP	3.2	lb/hr	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	GCP	7.3	lb/hr	BACT	GE 7FA
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	OxCat/GCP	0.0009	lb/MMBtu	BACT	MHI M501 GAC
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0040	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	OxCat, DLN, GCP	0.0169	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	OxCat, DLN, GCP	0.0169	lb/MMBtu	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP	0.1015	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	OxCat/GCP	0.3074	lb/MMBtu	BACT	
OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	1,882	MMBtu/hr	GCP	0.3	ppm	BACT	SIEMENS V84.3A
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	OxCat	0.7	ppm	BACT	Mitsubishi M501JAC
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	OxCat	1.0	ppm	BACT	
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	OxCat	1.0	ppm	BACT	
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	GCP	1.0	ppm	BACT	GE 7HA.02
FL-0364	SEMINOLE GENERATING STATION	SEMINOLE ELECTRIC COOPERATIVE, INC.	3/21/2018	3,514	MMBtu/hr	OxCat	1.0	ppm	BACT	GE 7HA.02
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	OxCat	1.0	ppm	BACT	Siemens SGT6-5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	1.0	ppm	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	OxCat	1.0	ppm	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	OxCat	1.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	1/31/2013	472		OxCat	1.0	ppm	BACT	
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	240	MW	OxCat	1.0	ppm	BACT	Siemens Model F5 (SF5
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	2,333	MMBtu/hr	None	1.2	ppm	BACT	
FL-0337	POLK POWER STATION	TAMPA ELECTRIC COMPANY	10/14/2012	1,160	MW	Fuel	1.4	ppm	BACT	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	GCP	1.4	ppm	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	OxCat	1.6	ppm	BACT	
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	OxCat	1.9	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
CA-1178	APPLIED ENERGY LLC	APPLIED ENERGY LLC	3/20/2009			OxCat	2.0	ppm	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	None	2.0	ppm	BACT	
GA-0138	LIVE OAKS POWER PLANT	LIVE OAKS COMPANY, LLC	4/8/2010	600	MW	OxCat/GCP	2.0	ppm	BACT	SGT6-5000F.
ID-0018	LANGLEY GULCH POWER PLANT	IDAHO POWER COMPANY	6/25/2010	2,375	MMBtu/hr	OxCat, DLN, GCP	2.0	ppm	BACT	Siemens SGT6-5000F
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	OxCat	2.0	ppm	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	OxCat	2.0	ppm	BACT	
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	OxCat	2.0	ppm	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	Mitsubishi M501-GAC
TX-0546	PATTILLO BRANCH POWER PLANT	PATTILLO BRANCH POWER COMPANY LLC	6/17/2009	350	MW	OxCat	2.0	ppm	BACT	GE 7FA, GE 7FB, AND SIEMENS SGT6-5000F.
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	OxCat/GCP	2.0	ppm	BACT	GE 7FA
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP	2.0	ppm	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	GCP/Fuel	2.0	ppm	BACT	Siemens/Westinghouse 501F
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	GCP/Fuel	2.0	ppm	BACT	GE 7FA
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	7/16/2014	87	MW	OxCat	2.0	ppm	BACT	
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	2/7/2013	650	MW	OxCat	2.0	ppm	BACT	GE 7FA.04; (2 Siemens SGT6-5000F(4; or (3 Siemens SGT6-5000F(5.
TX-0709	SAND HILL ENERGY CENTER	CITY OF AUSTIN	9/13/2013	174	MW	None	2.0	ppm	BACT	GE 7FA
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	TENASKA BROWNSVILLE PARTNERS, LLC	4/29/2014	274	MW	OxCat	2.0	ppm	BACT	
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	OxCat	2.0	ppm	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	OxCat	2.0	ppm	BACT	Alstom GT36
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	OxCat	2.0	ppm	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	OxCat	2.0	ppm	BACT	Siemens or GE
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	OxCat/GCP	2.0	ppm	BACT	GE Frame 7FA.04
TX-0548	MADISON BELL ENERGY CENTER	MADISON BELL PARTNERS LP	8/18/2009	275	MW	GCP	2.5	ppm	BACT	GE PG7121(EA
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	426	MW	OxCat/GCP	3.5	ppm	BACT	Siemens SGT6-5000F5
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	OxCat/GCP	4.0	ppm	BACT	
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	LAMAR POWER PARTNERS II LLC	6/22/2009	250	MW	GCP	4.0	ppm	BACT	GE 7FAS OR 250 MW MITSUBISHI 501GS
TX-0710	VICTORIA POWER STATION	VICTORIA WLE L.P.	12/1/2014	197	MW	OxCat	4.0	ppm	BACT	GE 7FA.04
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	11/20/2014	497	MW	OxCat	4.0	ppm	BACT	MHI J model
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	SCR/OxCat	4.0	ppm	BACT	GE Model 7HA.02
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	GCP	4.9	ppm	BACT	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,142	MMBtu/hr	OxCat	5.0	ppm	BACT	SIEMENS SGT6-5000F
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	OxCat/GCP	5.0	ppm	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	OxCat/GCP	5.0	ppm	BACT	Siemens SGT6-5000F5
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	None	22	tpy	BACT	
				PM10						
FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	1,860	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	GE 7241 FA CTG
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	8.9	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	8.9	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1198	MORRO BAY POWER PLANT	DYNERGY MORRO BAY LLC	9/25/2008	180	MW	Fuel	11.0	lb/hr	BACT	GE Frame 7, Model PG7241
CA-1198	MORRO BAY POWER PLANT	DYNERGY MORRO BAY LLC	9/25/2008	180	MW	Fuel	11.0	lb/hr	BACT	GE Frame 7, Model PG7241
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	GCP/Fuel	11.0	lb/hr	BACT	SGT6-500FEE
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	1,350	MW	Fuel	11.1	lb/hr	BACT	SGT6-5000F CTGs or four GE Frame 7FA CTGs
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	11.7	lb/hr	BACT	GE 7HA.02
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	11.8	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	11.8	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	Fuel	13.3	lb/hr	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	13.5	lb/hr	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	15.0	lb/hr	BACT	GE 7FA
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	GCP/Fuel	16.0	lb/hr	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	GCP/Fuel	17.9	lb/hr	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	GCP/Fuel	18.0	lb/hr	BACT	GE 7FA
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	None	18.3	lb/hr	BACT	GE 7HA.02
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP/Fuel	19.4	lb/hr	BACT	Siemens or GE
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	19.9	lb/hr	BACT	GE 7FA
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	None	21.4	lb/hr	BACT	Alstom GT36
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens/Westinghouse 501F
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	250	MW	DLN	30.2	lb/hr	BACT	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	210	MW	None	35.5	lb/hr	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	GCP/Fuel	35.5	lb/hr	BACT	Siemens or GE
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	Fuel	42.3	lb/hr	BACT	Mitsubishi M501-GAC
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	43.0	lb/hr	BACT	GE Model 7HA.02
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	0.0018	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	0.0020	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	Fuel	0.0023	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0024	lb/MMBtu	BACT	
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	MHI M501 GAC
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0032	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0033	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0036	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	GCP/Fuel	0.0037	lb/MMBtu	BACT	
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0037	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	7/25/2012	4,692	MMBtu/hr	GCP/Fuel	0.0041	lb/MMBtu	BACT	GE
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	0.0042	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0042	lb/MMBtu	BACT	Siemens
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	Fuel	0.0048	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	0.0062	lb/MMBtu	BACT	GE Energy 7F Series 5 Rapid Response
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	Fuel	0.0066	lb/MMBtu	BACT	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0066	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0069	lb/MMBtu	BACT	Siemens
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT	
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	GCP/Fuel	0.0080	lb/MMBtu	BACT	GE F-class advanced
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT	
CO-0073	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	7/22/2010	373	MMBtu/hr	GCP/Fuel	0.0115	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	GCP	0.0440	lb/MMBtu	BACT	
PM10 (filterable only)										
FL-0337	POLK POWER STATION	TAMPA ELECTRIC COMPANY	10/14/2012	1,160	MW	GCP	2.0	GR S/100 SCF	BACT	
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	Fuel	0.0024	lb/MMBtu	BACT	GE
OR-0048	CARTY PLANT	PORTLAND GENERAL ELECTRIC	12/29/2010	2,866	MMBtu/hr	Fuel	0.0025	lb/MMBtu	BACT	
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	Fuel	0.0029	lb/MMBtu	BACT	GE
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	0.0036	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,142	MMBtu/hr	None	0.0051	lb/MMBtu	BACT	SIEMENS SGT6-5000F
AK-0073	INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	12/20/2010	45	MW	Fuel	0.0066	lb/MMBtu	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP/Fuel	0.0078	lb/MMBtu	BACT	
LA-0136	PLAQUEMINE COGENERATION FACILITY	THE DOW CHEMICAL COMPANY	7/23/2008	2,876	MMBtu/hr	Fuel	0.0116	lb/MMBtu	BACT	GE FRAME 7 FA
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	607	MMBtu/hr	GCP/Fuel	0.0198	lb/MMBtu	BACT	
PM2.5 (total)										
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	GE 7HA.02
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	1,350	MW	Fuel	11.1	lb/hr	BACT	SGT6-5000F CTGs or four GE Frame 7FA CTGs
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	11.7	lb/hr	BACT	GE 7HA.02
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	7/16/2014	87	MW	None	15.2	lb/hr	BACT	GE 7EA
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	GCP/Fuel	16.0	lb/hr	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	GCP/Fuel	17.9	lb/hr	BACT	SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	None	18.0	lb/hr	BACT	GE 7FA
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	None	18.3	lb/hr	BACT	GE 7HA.02
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP/Fuel	19.4	lb/hr	BACT	Siemens or GE
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	None	21.4	lb/hr	BACT	Alstom GT36
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP/Fuel	22.1	lb/hr	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP/Fuel	22.2	lb/hr	BACT	Siemens SGT6-5000F5
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	None	27.0	lb/hr	BACT	Siemens/Westinghouse 501F
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	Fuel	33.4	lb/hr	BACT	GE 7FA
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	210	MW	None	35.5	lb/hr	BACT	Siemens or GE

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	GCP/Fuel	35.5	lb/hr	BACT	Siemens or GE
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	43.0	lb/hr	BACT	GE Model 7HA.02
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0024	lb/MMBtu	BACT	
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	MHI M501 GAC
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	0.0036	lb/MMBtu	BACT	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	GCP/Fuel	0.0037	lb/MMBtu	BACT	
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0037	lb/MMBtu	BACT	GE Frame 7FA.04
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	0.0040	lb/MMBtu	BACT	
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	0.0040	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	0.0042	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0042	lb/MMBtu	BACT	Siemens
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	GCP	0.0044	lb/MMBtu	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	Fuel	0.0048	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT	
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	0.0062	lb/MMBtu	BACT	GE Energy 7F Series 5 Rapid Response
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	130	MW	None	0.0066	lb/MMBtu	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	Fuel	0.0066	lb/MMBtu	BACT	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0066	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0069	lb/MMBtu	BACT	Siemens
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
PM2.5 (filterable only)										
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0025	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP/Fuel	0.0078	lb/MMBtu	BACT	
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	607	MMBtu/hr	GCP/Fuel	0.0198	lb/MMBtu	BACT	
Greenhouse Gases - CO2										
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	809	lb/MW-hr	BACT	GE HA.01
TX-0761	SR BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER	9/15/2015	301	MMBtu/hr	None	825	lb/MW-hr	BACT	GE 7HA, GE7FA, MHI510G, SF5
TX-0762	CEDAR BAYOU ELECTRIC GENERATING STATION	NRG TEXAS POWER	9/15/2015	301	MMBtu/hr	None	825	lb/MW-hr	BACT	GE 7HA, GE7FA, MHI510G, SF5
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	None	869	lb/MW-hr	BACT	SGT6-500FEE
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	879	lb/MW-hr	BACT	GE Model 7HA.02
TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	11/29/2012	180	MW	None	920	lb/MW-hr	BACT	Siemens Model FD3
TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	11/29/2012	180	MW	None	920	lb/MW-hr	BACT	Siemens Model FD3
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	CALPINE CORPORATION-CHANNEL ENERGY CENTER, LLC	11/29/2012	180	MW	None	920	lb/MW-hr	BACT	Siemens Model FD2
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	CALPINE CORPORATION-CHANNEL ENERGY CENTER, LLC	11/29/2012	180	MW	None	920	lb/MW-hr	BACT	Siemens Model FD2
TX-0664	LON C. HILL POWER STATION	LON C. HILL, LP	10/28/2014	700	MW	None	920	lb/MW-hr	BACT	Siemens SGT6-5000F or GE 7FA.04
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	None	925	lb/MW-hr	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	None	925	lb/MW-hr	BACT	GE7FA.05 OR Siemens SGT6 5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	951	lb/MW-hr	BACT	Siemens SGT6-5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	951	lb/MW-hr	BACT	Siemens SGT6-5000F
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	1,000	lb/MW-hr	BACT	GE H class
Greenhouse Gase - CO2 Equivalents										
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	None	7,109	BTU/KW-HR	BACT	GE F class
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	Fuel	7,273	BTU/KW-HR	BACT	Mitsubishi J Class
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP	7,646	BTU/KW-HR	BACT	Siemens SGT6-5000F
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	GCP	53.04	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	GCP	57.07	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	GCP	57.07	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP	57.53	lb/MMBtu	BACT	H Class?
TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	11/10/2011	1,746	MMBtu/hr	GCP	87.85	lb/MMBtu	BACT	GE 7FA
DE-0024	GARRISON ENERGY CENTER	GARRISON ENERGY CENTER, LLC/ CALPINE CORPORATION	1/30/2013	2,260	MMBtu/hr	Fuel	101.66	lb/MMBtu	BACT	GE 7FA
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	10/10/2012	3,277	MMBtu/hr	GCP	103.12	lb/MMBtu	BACT	F Class
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	103.50	lb/MMBtu	BACT	GE H class
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP	117.10	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP	119.67	lb/MMBtu	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	None	122.34	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP	128.71	lb/MMBtu	BACT	
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	133.33	lb/MMBtu	BACT	Siemens SGT6-5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	133.33	lb/MMBtu	BACT	Siemens SGT6-5000F
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	None	774	lb/MW-hr	BACT	Never built. In 2011, proposed turbines were GE. Currently proposed turbines are Siemens STG6-5000F
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	Fuel	792	lb/MW-hr	BACT	GE Frame 7FA.04
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	825	lb/MW-hr	BACT	GE Energy 7F Series 5 Rapid Response
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	GCP	840	lb/MW-hr	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	850	lb/MW-hr	BACT	GE 7HA.02
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	None	865	lb/MW-hr	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	1,127	MW	GCP	865	lb/MW-hr	BACT	GE 7FA.0
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	GCP/Fuel	886	lb/MW-hr	BACT	Alstom GT36
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	GCP	887	lb/MW-hr	BACT	GE
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	888	lb/MW-hr	BACT	GE 7HA.02
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	888	lb/MW-hr	BACT	GE 7HA.02
TX-0748	FGE POWER, FGE TEXAS PROJECT	FGE POWER, LLC	4/28/2014	231	MW	None	889	lb/MW-hr	BACT	Alstom GT24
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	889	MW	GCP	901	lb/MW-hr	BACT	GE 7FA.0
TX-0805	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY	7/19/2016	462	MW	GCP	917	lb/MW-hr	BACT	
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP	924	lb/MW-hr	BACT	Siemens or GE
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	7/25/2012	4,692	MMBtu/hr	GCP	925	lb/MW-hr	BACT	GE
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	889	MW	GCP	929	lb/MW-hr	BACT	MHI 501GAC
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	889	MW	GCP	929	lb/MW-hr	BACT	MHI 501GAC
TX-0743	AUSTIN ENERGY, SAND HILL ENERGY CENTER	CITY OF AUSTIN	9/29/2014	222	MW	None	930	lb/MW-hr	BACT	GE 7FA.04
TX-0787	TRINIDAD GENERATING FACILITY	SOUTHERN POWER	3/1/2016	497	MW	GCP	937	lb/MW-hr	BACT	
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	748	MW	GCP	944	lb/MW-hr	BACT	GE 7FA.0
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	GCP/Fuel	947	lb/MW-hr	BACT	Siemens
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	130	MW	None	954	lb/MW-hr	BACT	
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	4/28/2017	426	MW	Fuel	960	lb/MW-hr	BACT	Siemens SGT6-5000F5
TX-0791	ROCKWOOD ENERGY CENTER	ROCKWOOD ENERGY CENTER, LLC	3/18/2016	915	MW	GCP	965	lb/MW-hr	BACT	Siemens SCC6-8000H(1.4
TX-0810	DECORDOVA STEAM ELECTRIC STATION (DECORDOVA ST	DECORDOVA II POWER COMPANY LLC	10/4/2016	213	MW	GCP/Fuel	966	lb/MW-hr	BACT	GE 7FA
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP/Fuel	995	lb/MW-hr	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	1,000	lb/MW-hr	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	1,000	lb/MW-hr	BACT	
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP	1,000	lb/MW-hr	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP	1,000	lb/MW-hr	BACT	Siemens SGT6-5000F5
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	GCP/Fuel	1,000	lb/MW-hr	BACT	Mitsubishi M501-GAC
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP/Fuel	1,071	lb/MW-hr	BACT	
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	4/19/2016	1,339	MMBtu/hr	OxCat/GCP	1,800	lb/MW-hr	BACT	
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	GOLDEN PASS PRODUCTS, LLC	9/11/2015	16	MW	GCP	614,533	tpy	BACT	GE Frame 7
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	250	MW	None	1,022,756	tpy	BACT	
			Sulfuric Acid Mist							
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	12/19/2014	240	MW	None	0.50	GR S/100 SCF	BACT	Siemens Model F5 (SF5

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	Fuel	0.75	GR S/100 SCF	BACT	
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP/Fuel	1.00	GR S/100 SCF	BACT	Siemens or GE
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	2.00	GR S/100 SCF	BACT	GE 7HA.02
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	2.00	GR S/100 SCF	BACT	GE Model 7HA.02
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	GCP/Fuel	5.00	GR S/100 SCF	BACT	Siemens or GE
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	0.18	lb/hr	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	0.23	lb/hr	BACT	GE 7FA
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	Fuel	2.20	lb/hr	BACT	GE F class
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	Fuel	2.37	lb/hr	BACT	Alstom GT36
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	3.61	lb/hr	BACT	GE 7HA.02
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	4.26	lb/hr	BACT	GE 7HA.02
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	None	4.60	lb/hr	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	Fuel	13.68	lb/hr	BACT	GE 7FA
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	210	MW	None	15.56	lb/hr	BACT	Siemens or GE
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	Fuel	0.00030	lb/MMBtu	BACT	MHI M501 GAC
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	Fuel	0.00033	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	Fuel	0.00033	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	Fuel	0.00050	lb/MMBtu	BACT	
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel	0.00055	lb/MMBtu	BACT	
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.00070	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	Fuel	0.00070	lb/MMBtu	BACT	
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.00071	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.00071	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.00075	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	0.00087	lb/MMBtu	BACT	
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	Fuel	0.00087	lb/MMBtu	BACT	
LA-0224	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	2,110	MMBtu/hr	SCR/Fuel	0.00088	lb/MMBtu	BACT	
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	0.00100	lb/MMBtu	BACT	GE Energy 7F Series 5 Rapid Response
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	0.00320	lb/MMBtu	BACT	Siemens SGT6-5000F
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	0.00320	lb/MMBtu	BACT	
DE-0024	GARRISON ENERGY CENTER	GARRISON ENERGY CENTER, LLC/ CALPINE CORPORATION	1/30/2013	2,260	MMBtu/hr	None	0.01075	lb/MMBtu	BACT	
			PM10							
FL-0304	CANE ISLAND POWER PARK	FLORIDA MUNICIPAL POWER AGENCY (FMPA	9/8/2008	1,860	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	GE 7241 FA CTG
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	8.9	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	8.9	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1198	MORRO BAY POWER PLANT	DYNERGY MORRO BAY LLC	9/25/2008	180	MW	Fuel	11.0	lb/hr	BACT	GE Frame 7, Model PG7241
CA-1198	MORRO BAY POWER PLANT	DYNERGY MORRO BAY LLC	9/25/2008	180	MW	Fuel	11.0	lb/hr	BACT	GE Frame 7, Model PG7241
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	GCP/Fuel	11.0	lb/hr	BACT	SGT6-500FEE
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	1,350	MW	Fuel	11.1	lb/hr	BACT	SGT6-5000F CTGs or four GE Frame 7FA CTGs
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	11.7	lb/hr	BACT	GE 7HA.02
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	11.8	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
CA-1192	AVENAL ENERGY PROJECT	AVENAL POWER CENTER LLC	6/21/2011	180	MW	Fuel	11.8	lb/hr	BACT	Never built. Proposed Model GE 7241 FA
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	Fuel	13.3	lb/hr	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	13.5	lb/hr	BACT	GE 7FA
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	15.0	lb/hr	BACT	GE 7FA

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	GCP/Fuel	16.0	lb/hr	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	GCP/Fuel	17.9	lb/hr	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	GCP/Fuel	18.0	lb/hr	BACT	GE 7FA
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	None	18.3	lb/hr	BACT	GE 7HA.02
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP/Fuel	19.4	lb/hr	BACT	Siemens or GE
OH-0356	DUKE ENERGY HANGING ROCK ENERGY	DUKE ENERGY HANGING ROCK, LLC	12/18/2012	172	MW	Fuel	19.9	lb/hr	BACT	GE 7FA
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	None	21.4	lb/hr	BACT	Alstom GT36
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens/Westinghouse 501F
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	250	MW	DLN	30.2	lb/hr	BACT	
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	210	MW	None	35.5	lb/hr	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	GCP/Fuel	35.5	lb/hr	BACT	Siemens or GE
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	3/5/2014	2,988	MMBtu/hr	Fuel	42.3	lb/hr	BACT	Mitsubishi M501-GAC
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	43.0	lb/hr	BACT	GE Model 7HA.02
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	0.0018	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	0.0020	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	Fuel	0.0023	lb/MMBtu	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0024	lb/MMBtu	BACT	
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	MHI M501 GAC
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0032	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0033	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0036	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	GCP/Fuel	0.0037	lb/MMBtu	BACT	
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0037	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	7/25/2012	4,692	MMBtu/hr	GCP/Fuel	0.0041	lb/MMBtu	BACT	GE
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	0.0042	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0042	lb/MMBtu	BACT	Siemens
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	Fuel	0.0048	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT	
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	0.0062	lb/MMBtu	BACT	GE Energy 7F Series 5 Rapid Response
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	Fuel	0.0066	lb/MMBtu	BACT	
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0066	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0069	lb/MMBtu	BACT	Siemens
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT	
MD-0041	CPV ST. CHARLES	CPV MARYLAND, LLC	4/23/2014	725	MW	GCP/Fuel	0.0080	lb/MMBtu	BACT	GE F-class advanced
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT	
CO-0073	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	7/22/2010	373	MMBtu/hr	GCP/Fuel	0.0115	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	GCP	0.0440	lb/MMBtu	BACT	
			PM10 (filterable only)							
FL-0337	POLK POWER STATION	TAMPA ELECTRIC COMPANY	10/14/2012	1,160	MW	GCP	2.0	GR S/100 SCF	BACT	
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	Fuel	0.0024	lb/MMBtu	BACT	GE
OR-0048	CARTY PLANT	PORTLAND GENERAL ELECTRIC	12/29/2010	2,866	MMBtu/hr	Fuel	0.0025	lb/MMBtu	BACT	
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	11/1/2012	4,595	MMBtu/hr	Fuel	0.0029	lb/MMBtu	BACT	GE
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	0.0036	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,142	MMBtu/hr	None	0.0051	lb/MMBtu	BACT	SIEMENS SGT6-5000F
AK-0073	INTERNATIONAL STATION POWER PLANT	CHUGACH ELECTRIC ASSOCIATION	12/20/2010	45	MW	Fuel	0.0066	lb/MMBtu	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP/Fuel	0.0078	lb/MMBtu	BACT	
LA-0136	PLAQUEMINE COGENERATION FACILITY	THE DOW CHEMICAL COMPANY	7/23/2008	2,876	MMBtu/hr	Fuel	0.0116	lb/MMBtu	BACT	GE FRAME 7 FA
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	607	MMBtu/hr	GCP/Fuel	0.0198	lb/MMBtu	BACT	
			PM2.5 (total)							
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	3/9/2016	3,096	MMBtu/hr	Fuel	2.0	GR S/100 SCF	BACT	GE 7HA.02
TX-0590	KING POWER STATION	PONDERA CAPITAL MANAGEMENT GP INC	8/5/2010	1,350	MW	Fuel	11.1	lb/hr	BACT	SGT6-5000F CTGs or four GE Frame 7FA CTGs
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	11.7	lb/hr	BACT	GE 7HA.02
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	12.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	FREEPORT LNG DEVELOPMENT LP	7/16/2014	87	MW	None	15.2	lb/hr	BACT	GE 7EA
TX-0767	LON C. HILL POWER STATION	LON C. HILL, L.P.	10/2/2015	195	MW	GCP/Fuel	16.0	lb/hr	BACT	Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two GE 7FA CTGs and a D-11 ST.
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	GCP/Fuel	17.9	lb/hr	BACT	SIEMENS H-CLASS (SGT-8000H VERSION 1.4-OPTIMIZED
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	Fuel	18.0	lb/hr	BACT	Never built. No turbine specified in Application for Certification of Project
TX-0620	ES JOSLIN POWER PLANT	CALHOUN PORT AUTHORITY	9/12/2012	195	MW	None	18.0	lb/hr	BACT	GE 7FA
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	None	18.3	lb/hr	BACT	GE 7HA.02
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	3/24/2016	231	MW	GCP/Fuel	19.4	lb/hr	BACT	Siemens or GE
TX-0773	FGE EAGLE PINES PROJECT	FGE EAGLE PINES, LLC	11/4/2015	321	MW	None	21.4	lb/hr	BACT	Alstom GT36
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP/Fuel	22.1	lb/hr	BACT	Siemens SGT6-5000F5
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	360	MW	GCP/Fuel	22.2	lb/hr	BACT	Siemens SGT6-5000F5
TX-0618	CHANNEL ENERGY CENTER LLC	CHANNEL ENERGY CENTER LLC	10/15/2012	180	MW	GCP/Fuel	27.0	lb/hr	BACT	Siemens 501F
TX-0619	DEER PARK ENERGY CENTER	DEER PARK ENERGY CENTER LLC	9/26/2012	180	MW	None	27.0	lb/hr	BACT	Siemens/Westinghouse 501F
TX-0600	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	9/1/2011	390	MW	Fuel	33.4	lb/hr	BACT	GE 7FA
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	EAGLE MOUNTAIN POWER COMPANY LLC	6/18/2015	210	MW	None	35.5	lb/hr	BACT	Siemens or GE
TX-0789	DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	3/8/2016	231	MW	GCP/Fuel	35.5	lb/hr	BACT	Siemens or GE
TX-0730	COLORADO BEND ENERGY CENTER	COLORADO BEND II POWER, LLC	4/1/2015	1,100	MW	GCP	43.0	lb/hr	BACT	GE Model 7HA.02
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	1/4/2017	8,322	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0024	lb/MMBtu	BACT	
VA-0315	WARREN COUNTY POWER PLANT - DOMINION	VIRGINIA ELECTRIC AND POWER COMPANY	12/17/2010	2,996	MMBtu/hr	Fuel	0.0027	lb/MMBtu	BACT	MHI M501 GAC
PA-0296	BERKS HOLLOW ENERGY ASSOC LLC/ONTELAUNEE	BERKS HOLLOW ENERGY ASSOC LLC	12/17/2013	3,046	MMBtu/hr	None	0.0036	lb/MMBtu	BACT	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	8/16/2011	7,146	MMBtu/hr	GCP/Fuel	0.0037	lb/MMBtu	BACT	
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	11/21/2014	2,420	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0037	lb/MMBtu	BACT	GE Frame 7FA.04
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	0.0040	lb/MMBtu	BACT	
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	2,420	MMBtu/hr	None	0.0040	lb/MMBtu	BACT	
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,147	MMBtu/hr	GCP	0.0042	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0042	lb/MMBtu	BACT	Siemens
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,969	MMBtu/hr	GCP	0.0044	lb/MMBtu	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	Fuel	0.0048	lb/MMBtu	BACT	
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT	
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2,449	MMBtu/hr	None	0.0062	lb/MMBtu	BACT	GE Energy 7F Series 5 Rapid Response
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	130	MW	None	0.0066	lb/MMBtu	BACT	
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	7/25/2013	2,587	MMBtu/hr	Fuel	0.0066	lb/MMBtu	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	GCP/Fuel/Inlet Air Filter	0.0066	lb/MMBtu	BACT	
NJ-0082	WEST DEPTFORD ENERGY STATION	WEST DEPTFORD ENERGY ASSOCIATES	7/18/2014	2,362	MMBtu/hr	Fuel	0.0069	lb/MMBtu	BACT	Siemens
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	11/1/2013	2,807	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	GCP/Fuel	0.0140	lb/MMBtu	BACT	
PM2.5 (filterable only)										
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	3/7/2014	3,923	MMBtu/hr	Fuel	0.0025	lb/MMBtu	BACT	GE7FA.05 OR Siemens SGT6 5000F
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	8/31/2016	3,625	MMBtu/hr	GCP/Fuel	0.0048	lb/MMBtu	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	GCP/Fuel	0.0078	lb/MMBtu	BACT	
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	607	MMBtu/hr	GCP/Fuel	0.0198	lb/MMBtu	BACT	
Opacity										
IA-0107	MARSHALLTOWN GENERATING STATION	INTERSTATE POWER AND LIGHT	4/14/2014	2,258	MMBtu/hr	None	0	% OPACITY	BACT	Siemens SGT6-5000F
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	GCP	5	% OPACITY	BACT	
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,486	MMBtu/hr	GCP	5	% OPACITY	BACT	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	7/30/2008	2,333	MMBtu/hr	None	10	% OPACITY	BACT	
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	10	% OPACITY	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	5,579	MMBtu/hr	Fuel	10	% OPACITY	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	6,004	MMBtu/hr	Fuel	10	% OPACITY	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	6/18/2013	799	MW	Fuel	10	% OPACITY	BACT	Mitsubishi M501 GAC units or 2 Siemens SGT-8000H

Table D-1a Addendum: RBLC Tables for Combined Cycle Turbines (Natural Gas)
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type	Turbine Model
				Nitrogen Oxides						
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	DLN/GCP	17	PPMV @ 15% O2	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	DLN/GCP	17	PPMV @ 15% O2	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	DLN/GCP	15	PPMV @ 15% O2	BACT	
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW	SCR	2	PPM	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	DLN/SCR	2	PPMVD	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr	DLN/WI	23	PPMV	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr	DLN/WI	23	PPMV	BACT	
MI-0439	JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	04/02/2019	420	MW	SI/GCP/CBF	25	PPM	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	DLN/SCR	3	PPM	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	DLN/GCP	25	PPM	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	DLN/SCR	3	PPM	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	DLN/SCR/GCP	2	PPM	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	DLN/SCR	2	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	DLN/GCP	25	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	DLN/SCR	60	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	DLN/SCR	60	LB/H	BACT	
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	21042	MMCubic ft/yr	SCR/DLN/CBF	18.3	LB/H	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	DLN/SCR	2.5	PPMVD	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	DLN/SCR	2	PPMVD 15% O2	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	DLN/SCR	703	LB/TURBINE/CAL. DAY	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	DLN/SCR	60	LB/TURBINE/EVENT	BACT	
*VA-0334	DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	12/01/2020	3442	MMBTU/H	DLN/SCR	604	LBS	BACT	
*VA-0334	DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	12/01/2020	3442	MMBTU/H	DLN/SCR	604	LBS	BACT	
				Carbon Monoxide						
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	OxCat/GCP	5	PPMV @ 15% O2	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	OxCat/GCP	5	PPMV @ 15% O2	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	GCP/CBF	15	PPMV @ 15% O2	BACT	
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW	OxCat	23.8	LB/HR	BACT	
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	3864	mmBtu/hr	OxCat	2	PPMV	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	CBP/catalytic oxidation	4	PPMVD	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr		25	PPMV	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr		25	PPMV	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	OxCat/GCP	4	PPM	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	DLN/GCP	9	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	OxCat/GCP	4	PPM	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	OxCat/GCP	2	PPM	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	OxCat/GCP	4	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	DLN/GCP	9	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	OxCat/GCP	4	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	OxCat/GCP	4	PPM	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	OxCat	3	PPMVD	BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	0		OxCat	4	PPMVD	BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	14552539	MMBTU/YR	OxCat	3.5	PPMVD	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	1	PPMVD @ 15% O2	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	214	LB/TURBINE/DAY	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	444	LB/TURBINE/EVENT	BACT	
*VA-0334	DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	12/01/2020	3442	MMBTU/H	OxCat/GCP	416	LBS	BACT	
*VA-0334	DOMINION ENERGY - BRUNSWICK	VIRGINIA ELECTRIC AND POWER COMPANY	12/01/2020	3442	MMBTU/H	OxCat/GCP	416	LBS	BACT	

(a) SCR = selective catalytic reduction, DLN = dry, low-NOx burners, WI = water injection, GCP = good combustion practices, CBF = clean burning fuels, OxCat = oxidation catalyst

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type	Turbine Model
Volatile Organic Compounds										
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	OxCat/GCP	0.0022	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	OxCat/GCP	0.0022	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	GCP/CBF	0.0022	LB/MMBTU	BACT	
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW	OxCat	13.6	LB/HR	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	OxCat/GCP	4	PPMVD	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	OxCat/GCP	3	PPM	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	GCP	5	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	OxCat/GCP	3	PPM	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	OxCat/GCP	0.004	LB/MMBTU	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	GCP/CBF/Inlet Air Conditioning	4	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	GCP	5	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	OxCat/GCP	3	PPM	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	OxCat/GCP	3	PPM	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	OxCat/GCP/CBF	2	PPMVD	BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	0		OxCat	1	PPMVD	BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	14552539	MMBTU/YR	OxCat	1.5	PPMVD	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	0.7	PPMVD @ 15% O2	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	216	LB/TURBINE/EVENT	BACT	
PM_{10} (total)										
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	GCP/CBF	0.0063	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	GCP/CBF	0.0063	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	GCP/CBF	0.007	LB/MMBTU	BACT	
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW		0.004	LB/MMBTU	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	GCP/CBF	12.46	LB/H	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr	Good Combustion Controls	19	LB/HR	BACT	
*LA-0365	BIG CAJUN I POWER PLANT	LOUISIANA GENERATING, LLC	06/27/2019	1679	MM BTU/hr	Good Combustion Controls	19	LB/HR	BACT	
MI-0439	JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	04/02/2019	420	MW	Inlet Air Filters/GCP/CBF	4.9	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	4.5	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	GCP/CBF	0.006	LB/MMBTU	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	inlet air conditioning/CBF/GCP	19.8	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	4.5	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	21042	MMCubic ft/yr	CBF	11.58	LB/H	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	GCP/CBF	0.0052	LB/MMBTU	BACT	
PM_{10} (filterable only)										
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	0		CBF	0		BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	14552539	MMBTU/YR	CBF	0		BACT	
$PM_{2.5}$ (total)										
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	GCP/CBF	0.0063	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	GCP/CBF	0.0063	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	GCP/CBF	0.007	LB/MMBTU	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	GCP/CBF	12.46	LB/H	BACT	
MI-0439	JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	04/02/2019	420	MW	Inlet Air Filters/GCP/CBF	4.9	LB/HR	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	4.5	LB/H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	GCP/CBF	0.006	LB/MMBTU	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	inlet air conditioning/CBF/GCP	19.8	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	4.5	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	inlet air conditioning/CBF/GCP	6.02	LB/H	BACT	
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	21042	MMCubic ft/yr	CBF	11.58	LB/H	BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	GCP/CBF	0.0052	LB/MMBTU	BACT	

(a) SCR = selective catalytic reduction, DLN = dry, low-NOx burners, WI = water injection, GCP = good combustion practices, CBF = clean burning fuels, OxCat = oxidation catalyst

Table D-1a Addendum: RBLC Tables for Combined Cycle Turbines (Natural Gas)
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type	Turbine Model
				$PM_{2.5}$ (filterable only)						
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW		0.004	LB/MMBTU	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	GCP/CBF	0		BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	0		CBF	0		BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	14552539	MMBTU/YR	CBF	0		BACT	
				Greenhouse Gases - CO_2						
*AL-0328	PLANT BARRY	ALABAMA POWER COMPANY	11/09/2020	744	MW	Efficient Design	1000	LB/MWH	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	CBF/GCP/energy efficiency measures.	1000	LB/MW-H	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	CBF/GCP/energy efficiency measures.	1000	LB/MW-H	BACT	
				Greenhouse Gases - CO_2 Equivalents						
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	576	MMBtu/hr	GCP/CBF	117.1	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	431	MMBtu/hr	GCP/CBF	117.1	LB/MMBTU	BACT	
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	386	MMBtu/hr	GCP/CBF	117.1	LB/MMBTU	BACT	
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	3864	mmBtu/hr	GCP	4733910	TONS/YEAR	BACT	
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	2222	mm btu/h	CBF/GCP/energy-efficient design options	1096666	TONS/YR	BACT	
MI-0439	JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	04/02/2019	420	MW	CBF/GCP/energy efficiency measures	1000257	T/YR	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	CBF/GCP/energy efficiency measures	430349	T/YR	BACT	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	667	MMBTU/H	CBF/GCP/energy efficiency measures	430349	T/YR	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	Energy efficiency measures	2739722	T/YR	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	GCP/CBF/Inlet Air Conditioning	1911481	T/YR	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	CBF/GCP/energy efficiency measures	430349	T/YR	BACT	
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	667	MMBTU/H	CBF/GCP/energy efficiency measures	430349	T/YR	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	GCP/CBF	0		BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	0		CBF	0		BACT	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	03/17/2021	14552539	MMBTU/YR	CBF	0		BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	Energy efficient combustion practices/CBF	812	LB/CO2E/MW-H	BACT	
				Sulfuric Acid Mist						
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	3864	mmBtu/hr		5	POUNDS/HOUR	BACT	
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	625	MW	CBF	0.0013	LB/MMBTU	BACT	
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	3421	MMBTU/H	GCP/CBF	4.6	LB/H	BACT	
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	21042	MMCubic ft/yr	CBF	3.45	LB/H	BACT	
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	08/27/2021	230	MW	GCP/CBF	0		BACT	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	CBF	0.0012	LB/MMBTU	BACT	
				Opacity						
MI-0439	JACKSON GENERATING STATION	CONSUMERS ENERGY COMPANY	04/02/2019	420	MW	Inlet Air Filters/GCP/CBF	10	%	BACT	

(a) SCR = selective catalytic reduction, DLN = dry, low-NOx burners, WI = water injection, GCP = good combustion practices, CBF = clean burning fuels, OxCat = oxidation catalyst

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
Nitrogen Oxides										
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	15,119	GAL/H	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	48.4	LB/H	LAER	SIEMENS SGT6-5000F
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	720	H/YR	Selective catalytic Reduction Systems and Dry Low NOx	4	PPMVD@15% O2	LAER	GE 7HA.02
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	-		Water injection and selective catalytic reduction.	6	PPMVD @ 15% O2	LAER	F Class
Carbon Monoxide										
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,117	MMBtu/hr	OxCat	1.8	ppm	BACT	SIEMENS SGT6-5000F
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	OxCat	1.8	ppm	BACT	Mitsubishi M501JAC
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	OxCat	2	ppm	BACT	GE 7HA.01
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	OxCat	2	ppm	BACT	GE 7HA.01
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	OXCAT/GCP	2	ppm	BACT	GE 7HA.02
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	OXCAT/GCP	2	ppm	BACT	F class
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	SOUTHERN COMPANY/GEORGIA POWER	1/7/2008	254	MW	OxCat	9	ppm	BACT	Mitsubishi MHI 501-GI
Greenhouse Gases										
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	888	lb/MW-hr	BACT	GE 7HA.02
Sulfuric Acid Mist										
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	Fuel	2.31	lb/hr	BACT	
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	Fuel	2.31	lb/hr	BACT	
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	4.27	lb/hr	BACT	GE 7HA.02
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	Fuel	0.0005	lb/MMBtu	BACT	
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	Fuel	0.0005	lb/MMBtu	BACT	
Particulate Matter										
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	34.3	lb/hr	BACT	GE 7HA.02
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	8/1/2013	2,234	MMBtu/hr	Fuel	0.0368	lb/MMBtu	BACT	
PM10										
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	72	lb/hr	BACT	GE 7HA.02
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0168	lb/MMBtu	BACT	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,117	MMBtu/hr	None	0.02692	lb/MMBtu	BACT	SIEMENS SGT6-5000F
PM2.5										
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	None	42.6	lb/hr	BACT	
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	STONEGATE POWER, LLC	7/19/2016	663	MW	Fuel	72	lb/hr	BACT	GE 7HA.02
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	GCP	0.0168	lb/MMBtu	BACT	
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	None	42.6	lb/hr	BACT	
Volatile Organic Compounds										
CT-0157	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	OxCat	2	ppm	BACT	GE 7HA.01
CT-0158	CPV TOWANTIC, LLC	CPV TOWANTIC, LLC	11/30/2015	805	MW	OxCat	2	ppm	BACT	GE 7HA.01
CT-0161	KILLINGLY ENERGY CENTER	NTE CONNECTICUT, LLC	6/30/2017	2,639	MMBtu/hr	OxCat	2	ppm	BACT	Mitsubishi M501JAC
CT-0151	KLEEN ENERGY SYSTEMS, LLC	KLEEN ENERGY SYSTEMS, LLC	2/25/2008	2,117	MMBtu/hr	OxCat	3.6	ppm	BACT	SIEMENS SGT6-5000F

From December 2021 Application

Table D-1b Addendum: RBLC Tables for Combined Cycle Turbines (Fuel Oil)
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
Carbon Monoxide										
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	14.78	MMGAL/YR	OxCat/CBF	18.4	LB/H	BACT	
PM_{10} (total)										
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	14.78	MMGAL/YR	CBF	49.17	LB/H	BACT	
$PM_{2.5}$ (total)										
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	14.78	MMGAL/YR	CBF	49.17	LB/H	BACT	
Sulfuric Acid Mist										
NJ-0088	COGEN TECH LINDEN VENTURE LP	COGEN TECH LINDEN VENTURE LP	07/30/2019	14.78	MMGAL/YR	CBF	4.8	LB/H	BACT	

(a) SCR = selective catalytic reduction, DLN = dry, low-NOx burners, WI = water injection, GCP = good combustion practices, CBF = clean burning fuels, OxCat = oxidation catalyst

Table D-1c - RBLC Results for Combined Cycle Turbine Startup/Shutdown (Natural Gas)

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
				Nitrogen Oxides - Startup/Shutdown						
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	SCR/DLN	23	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	SCR/DLN	32	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	40	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	40	lb/event	BACT	
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	647	MMBtu/hr	SCR/DLN	44	lb/event	BACT	
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	554	MMBtu/hr	SCR/DLN	44	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	57	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	57	lb/event	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	110	MMBtu/hr	SCR/DLN	57	lb/event	BACT	
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	SCR/DLN	60	lb/event	BACT	SGT6-500FEE
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	SCR/DLN/GCP	71	lb/event	BACT	SGT6-500FEE
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	SCR/DLN/GCP	83	lb/event	BACT	SGT6-500FEE
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	96	lb/event	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	SCR/DLN	96	lb/event	BACT	
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	SCR/DLN	97	lb/event	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	SCR/DLN/GCP	105	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	SCR/DLN	115	lb/event	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	SCR/DLN/GCP	132	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	SCR	142	lb/event	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	SCR/DLN/GCP	153	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
MI-0405	MIDLAND COGENERATION VENTURE	MIDLAND COGENERATION VENTURE	4/23/2013	2,237	MMBtu/hr	SCR/DLN	186	lb/event	BACT	
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	SCR/DLN/GCP	245	lb/event	BACT	SGT6-500FEE
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	SCR/DLN	260	lb/event	BACT	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	None	443	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	SCR/DLN	456	lb/event	BACT	
OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	1,882	MMBtu/hr	DLN	568	lb/event	BACT	SIEMENS V84.3A
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	SCR/DLN	779	lb/event	BACT	
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	SCR/DLN	3,541	lb/event	BACT	
				Carbon Monoxide - Startup/Shutdown						
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	OxCat/GCP	60	lb/event	BACT	SGT6-500FEE
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	OxCat/GCP	156	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	OxCat	183	lb/event	BACT	
CA-1209	HIGH DESERT POWER PROJECT	HIGH DESERT POWER PROJECT LLC	3/11/2010	190	MW	OxCat	239	lb/event	BACT	
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	OxCat/GCP	269	lb/event	BACT	SGT6-500FEE
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	OxCat/GCP	311	lb/event	BACT	SGT6-500FEE
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	329	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	329	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	337	lb/event	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	110	MMBtu/hr	OxCat	337	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	410	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	410	lb/event	BACT	
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	10/18/2011	154	MW	OxCat	410	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	OxCat	484	lb/event	BACT	
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	CITY OF VICTORVILLE	3/11/2010	154	MW	OxCat	674	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	OxCat	680	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	OxCat	791	lb/event	BACT	
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	10/31/2014	235	MW	OxCat/GCP	1,064	lb/event	BACT	SGT6-500FEE
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	OxCat/GCP	1,216	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	OxCat	1,356	lb/event	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	OxCat/GCP	1,461	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	11/17/2017	1,935	MMBtu/hr	OxCat/GCP	1,580	lb/event	BACT	

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
OK-0129	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	1,882	MMBtu/hr	GCP	1,596	lb/event	BACT	SIEMENS V84.3A
OK-0157	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	9/5/2013	182	MMBtu/hr	None	1,750	lb/event	BACT	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	11/13/2015	286	MW	OxCat/GCP	1,772	lb/event	BACT	SGT-8000H VERSION 1.4-OPTIMIZED
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,300	MMBtu/hr	None	2,125	lb/event	BACT	
OK-0157	CHOUTEAU POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE INC	9/5/2013	178	MW	GCP	4,500	lb/event	BACT	
Particulate Matter - Startup/Shutdown										
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	6.0	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	12.8	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	30.8	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	48.8	lb/event	BACT	
PM10 -Startup/Shutdown										
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	6.0	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	12.8	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	30.8	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	Fuel	48.0	lb/event	BACT	
Volatile Organic Compounds -Startup/Shutdown										
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	None	23.9	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	None	38.0	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	None	47.4	lb/event	BACT	
CA-1211	COLUSA GENERATING STATION	PACIFIC GAS & ELECTRIC COMPANY	3/11/2011	172	MW	None	106.7	lb/event	BACT	

Table D-1c Addendum: RBLC Tables for Combined Cycle Turbines (Startup/Shutdown)
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type	Turbine Model
Nitrogen Oxides										
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	DLN/SCR	60	LB/TURBINE/EVENT	BACT	
Carbon Monoxide										
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	444	LB/TURBINE/EVENT	BACT	
Volatile Organic Compounds										
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	35000	MMCF/YR	OxCat/GCP	216	LB/TURBINE/EVENT	BACT	

(a) SCR = selective catalytic reduction, DLN = dry, low-NOx burners, WI = water injection, GCP = good combustion practices, CBF = clean burning fuels, OxCat = oxidation catalyst

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Carbon Monoxide								
OK-0168	Seminole Generating Station	5/5/2015	40.4	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	4/14/2014	60.1	MMBtu/hr	Ox Cat	0.0164	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	11/12/2008	93	MMBtu/hr	None	0.0200	lb/MMBtu	BACT-PSD
MD-0041	CPV St. Charles	4/23/2014	93	MMBtu/hr	GCP	0.0200	lb/MMBtu	BACT-PSD
NJ-0080	Hess Newark Energy Center	11/1/2012	100	MMBtu/hr	Clean Fuels	0.0245	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0354	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0354	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0354	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	0.0354	lb/MMBtu	BACT-PSD
OH-0354	Kraton Polymers U.S. LLC	1/15/2013	249	MMBtu/hr	GCP, Clean fuels	0.0360	lb/MMBtu	BACT-PSD
WI-0259	Manitowoc Public Utilities	4/16/2012	33	MMBtu/hr	None	0.0360	lb/MMBtu	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	3/10/2016	80	MMBtu/hr	GCP, Clean fuels	0.0360	lb/MMBtu	BACT-PSD
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0360	lb/MMBtu	BACT-PSD
AR-0121	El Dorado Chemical Company	11/18/2013	240	MMBtu/hr	GCP	0.0370	lb/MMBtu	BACT-PSD
LA-0240	Flopam Inc.	6/14/2010	25.1	MMBtu/hr	GCP	0.0370	lb/MMBtu	BACT-PSD
FL-0318	Highlands Ethanol Facility	12/10/2009	198	MMBtu/hr	None	0.0370	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	229	MMBtu/hr	GCP	0.0370	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	GCP	0.0370	lb/MMBtu	BACT-PSD
TX-0681	Olefins Plant	8/8/2014			GCP	0.0370	lb/MMBtu	BACT-PSD
GA-0127	Plant Mcdonough Combined Cycle	1/7/2008	200	MMBtu/hr	None	0.0370	lb/MMBtu	BACT-PSD
TX-0714	S R Bertron Electric Generating Station	12/19/2014	80	MMBtu/hr	LNB	0.0370	lb/MMBtu	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	7/19/2016	97.5	MMBtu/hr	GCP, Clean fuels	0.0370	lb/MMBtu	BACT-PSD
WY-0075	Cheyenne Prairie Generating Station	7/16/2014	25.06	MMBtu/hr	GCP	0.0375	lb/MMBtu	BACT-PSD
NY-0103	Cricket Valley Energy Center	2/3/2016	60	MMBtu/hr	GCP	0.0375	lb/MMBtu	BACT-PSD
NJ-0079	Woodbridge Energy Center	7/25/2012	91.6	MMBtu/hr	GCP, Clean fuels	0.0376	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0390	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0390	lb/MMBtu	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	GCP	0.0390	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	GCP	0.0400	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP	0.0400	lb/MMBtu	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	11/21/2014	100	MMBtu/hr	GCP	0.0400	lb/MMBtu	BACT-PSD
AL-0286	Mount Vernon Mill	3/25/2010	70	MMBtu/hr	None	0.0400	lb/MMBtu	BACT-PSD
OK-0137	Ponca City Refinery	2/9/2009	95	MMBtu/hr	Ultra LNB, GCP	0.0400	lb/MMBtu	BACT-PSD
OH-0350	Republic Steel	7/18/2012	65	MMBtu/hr	GCP	0.0400	lb/MMBtu	BACT-PSD
AL-0300	Thyssenkrupp Stainless USA, LLC	3/25/2010	28.6	MMBtu/hr	None	0.0400	lb/MMBtu	BACT-PSD
OR-0050	Troutdale Energy Center, LLC	3/5/2014	39.8	MMBtu/hr	LNB, FGR	0.0400	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	3/27/2013	217.5	MMBtu/hr	GCP	0.0500	lb/MMBtu	BACT-PSD
OH-0352	Oregon Clean Energy Center	6/18/2013	99	MMBtu/hr	GCP	0.0550	lb/MMBtu	BACT-PSD
AR-0138	Nucor Corporation - Nucor Steel, Arkansas	2/17/2012	50.4	MMBtu/hr	GCP	0.0610	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
SC-0112	Nucor Steel - Berkeley	5/5/2008	50.21	MMBtu/hr	GCP, Clean fuels	0.0610	lb/MMBtu	BACT-PSD
NY-0104	CPV Valley Energy Center	8/1/2013	73.5	MMBtu/hr	GCP	0.0721	lb/MMBtu	BACT-PSD
OK-0148	Buffalo Creek Processing Plant	9/12/2012	11.04	MMBtu/hr	None	0.0740	lb/MMBtu	BACT-PSD
OH-0336	Campbell Soup Company	12/14/2010			None	0.0750	lb/MMBtu	BACT-PSD
IA-0108	Iowa State University Power Plant	11/7/2013	213.6	MMBtu/hr	None	0.0750	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	GCP	0.0750	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	0.0770	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	0.0770	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	0.0770	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	17.5	MMBtu/hr	GCP	0.0800	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	24.59	MMBtu/hr	GCP	0.0800	lb/MMBtu	BACT-PSD
MD-0046	Keys Energy Center	10/31/2014	93	MMBtu/hr	GCP	0.0800	lb/MMBtu	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	3/9/2016	99.8	MMBtu/hr	GCP	0.0800	lb/MMBtu	BACT-PSD
OH-0323	Titan Tire Corporation of Bryan	6/5/2008	50.4	MMBtu/hr	None	0.0800	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	248	MMBtu/hr	GCP	0.0820	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP, Clean fuels	0.0824	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP, Clean fuels	0.0824	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	GCP, Clean fuels	0.0824	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	2/23/2009	80	MMBtu/hr	GCP	0.0825	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	GCP	0.0830	lb/MMBtu	BACT-PSD
OH-0315	New Steel International, Inc., Haverhill	5/6/2008	50.4	MMBtu/hr	None	0.0839	lb/MMBtu	BACT-PSD
OH-0310	American Municipal Power Generating Station	10/8/2009	150	MMBtu/hr	None	0.0840	lb/MMBtu	BACT-PSD
TX-0576	Pipe Manufacturing Steel Mini Mill	4/19/2010	40	MMBtu/hr	GCP	0.0842	lb/MMBtu	BACT-PSD
CA-1192	Avenal Energy Project	6/21/2011	37.4	MMBtu/hr	Ultra LNB, GCP, Clean fuels	50.0000	ppm	BACT-PSD
TX-0731	Corpus Christi Terminal Condensate Splitter	4/10/2015	129	MMBtu/hr	GCP	50.0000	ppm	BACT-PSD
TX-0751	Eagle Mountain Steam Electric Station	6/18/2015	73.3	MMBtu/hr	None	50.0000	ppm	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	50.0000	ppm	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	50.0000	ppm	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	40	MMBtu/hr	None	50.0000	ppm	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	110	MMBtu/hr	None	50.0000	ppm	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	13.2	MMBtu/hr	GCP	50.0000	ppm	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	40	MMBtu/hr	GCP	50.0000	ppm	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	95.7	MMBtu/hr	GCP	50.0000	ppm	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	40	MMBtu/hr	None	50.0000	ppm	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	35	MMBtu/hr	None	50.0000	ppm	BACT-PSD
TX-0708	La Paloma Energy Center	2/7/2013	150	MMBtu/hr	GCP	75.0000	ppm	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Greenhouse Gases - Carbon Dioxide								
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0568	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	116.8824	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	116.8824	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP	117.0000	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP	117.0000	lb/MMBtu	BACT-PSD
AR-0121	El Dorado Chemical Company	11/18/2013	240	MMBtu/hr	GCP	117.0000	lb/MMBtu	BACT-PSD
NY-0116	Fab 8, Luther Forest Technology Campus	3/29/2013			GCP, Clean fuels	118.0000	lb/MMBtu	BACT-PSD
NY-0116	Fab 8, Luther Forest Technology Campus	3/29/2013			GCP, Clean fuels	160.0000	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	546.8807	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide Equivalents								
KS-0029	The Empire District Electric Company	7/14/2015	18.6	MMBtu/hr	None	116.8741	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	GCP	117.0000	lb/MMBtu	BACT-PSD
OK-0148	Buffalo Creek Processing Plant	9/12/2012	11.04	MMBtu/hr	None	117.0000	lb/MMBtu	BACT-PSD
OR-0050	Troutdale Energy Center, LLC	3/5/2014	39.8	MMBtu/hr	Clean Fuels	117.0000	lb/MMBtu	BACT-PSD
OR-0050	Troutdale Energy Center, LLC	3/5/2014	39.8	MMBtu/hr	Clean Fuels	117.0000	lb/MMBtu	BACT-PSD
TX-0814	Ammonia And Urea Plant	1/5/2017	240	MMBtu/hr	GCP	117.0653	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	GCP	117.0982	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP, Clean fuels	117.0982	lb/MMBtu	BACT-PSD
WY-0075	Cheyenne Prairie Generating Station	7/16/2014	25.06	MMBtu/hr	GCP	117.1162	lb/MMBtu	BACT-PSD
AR-0121	El Dorado Chemical Company	11/18/2013	240	MMBtu/hr	GCP	117.4001	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	118.3469	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	118.3634	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	118.3645	lb/MMBtu	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	13.2	MMBtu/hr	GCP	118.4793	lb/MMBtu	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	40	MMBtu/hr	GCP	118.4817	lb/MMBtu	BACT-PSD
NY-0103	Cricket Valley Energy Center	2/3/2016	60	MMBtu/hr	GCP, Clean fuels	119.0000	lb/MMBtu	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	1/30/2014	80	MMBtu/hr	None	119.0000	lb/MMBtu	BACT-PSD
TX-0812	Crude Oil Processing Facility	10/31/2016	104	MMBtu/hr	GCP	120.3021	lb/MMBtu	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	11/21/2014	100	MMBtu/hr	Clean Fuels	120.8100	lb/MMBtu	BACT-PSD
IA-0108	Iowa State University Power Plant	11/7/2013	213.6	MMBtu/hr	None	121.3723	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	490.6173	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	2,384.4000	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Sulfuric Acid Mist								
IA-0107	Marshalltown Generating Station	4/14/2014	60.1	MMBtu/hr	None	0.0001	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	11/12/2008	93	MMBtu/hr	None	0.0001	lb/MMBtu	BACT-PSD
OH-0352	Oregon Clean Energy Center	6/18/2013	99	MMBtu/hr	Clean Fuels	0.0001	lb/MMBtu	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	7/19/2016	97.5	MMBtu/hr	Clean Fuels	0.0001	lb/MMBtu	BACT-PSD
NY-0103	Cricket Valley Energy Center	2/3/2016	60	MMBtu/hr	Clean Fuels	0.0001	lb/MMBtu	BACT-PSD
NY-0104	CPV Valley Energy Center	8/1/2013	73.5	MMBtu/hr	Clean Fuels	0.0002	lb/MMBtu	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	3/10/2016	80	MMBtu/hr	Clean Fuels	0.0003	lb/MMBtu	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	1/30/2014	80	MMBtu/hr	None	0.0009	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	GCP, Clean fuels	0.0040	lb/MMBtu	BACT-PSD
Nitrogen Dioxide								
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	SCR, LNB	0.0032	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	SCR, LNB	0.0032	lb/MMBtu	BACT-PSD
TX-0731	Corpus Christi Terminal Condensate Splitter	4/10/2015	129	MMBtu/hr	SCR	0.0060	lb/MMBtu	BACT-PSD
CA-1206	Stockton Cogen Company	9/16/2011	178	MMBtu/hr	None	0.0085	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	Ultra LNB	0.0100	lb/MMBtu	BACT-PSD
MD-0046	Keys Energy Center	10/31/2014	93	MMBtu/hr	Ultra LNB, GCP, Clean fuels	0.0100	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	Ultra LNB, GCP, Clean fuels	0.0100	lb/MMBtu	BACT-PSD
TX-0681	Olefins Plant	8/8/2014			SCR, LNG, FGR	0.0100	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	24	MMBtu/hr	LNB	0.0108	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	11/12/2008	93	MMBtu/hr	LNB, FGR	0.0110	lb/MMBtu	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	95.7	MMBtu/hr	LNB, FGR	0.0110	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	4/14/2014	60.1	MMBtu/hr	None	0.0130	lb/MMBtu	BACT-PSD
LA-0305	Lake Charles Methanol Facility	6/30/2016	225	MMBtu/hr	SCR	0.0150	lb/MMBtu	BACT-PSD
WY-0075	Cheyenne Prairie Generating Station	7/16/2014	25.06	MMBtu/hr	Ultra LNB, FGR	0.0175	lb/MMBtu	BACT-PSD
AR-0121	El Dorado Chemical Company	11/18/2013	240	MMBtu/hr	LNB, FGR	0.0180	lb/MMBtu	BACT-PSD
MI-0389	Karn Weadock Generating Complex	12/29/2009	220	MMBtu/hr	LNB	0.0180	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	LNB, FGR, GCP	0.0194	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	LNB, FGR	0.0194	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	LNB, FGR	0.0194	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	Ultra LNB, FGR	0.0194	lb/MMBtu	BACT-PSD
TX-0708	La Paloma Energy Center	2/7/2013	150	MMBtu/hr	LNB	0.0200	lb/MMBtu	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	11/21/2014	100	MMBtu/hr	Ultra LNB, FGR, GCP	0.0200	lb/MMBtu	BACT-PSD
OH-0352	Oregon Clean Energy Center	6/18/2013	99	MMBtu/hr	LNB, FGR	0.0200	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	16.8	MMBtu/hr	LNB, FGR	0.0300	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	31.38	MMBtu/hr	LNB	0.0306	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	LNB, FGR	0.0320	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	LNB, Clean Fuels, GCP	0.0350	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	LNB, Clean Fuels, GCP	0.0350	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	LNB, GCP, Clean fuels	0.0350	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	35.4	MMBtu/hr	LNB	0.0350	lb/MMBtu	BACT-PSD
AL-0286	Mount Vernon Mill	3/25/2010	70	MMBtu/hr	LNB, FGR	0.0350	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	5/5/2008	50.21	MMBtu/hr	Ultra LNB	0.0350	lb/MMBtu	BACT-PSD
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0350	lb/MMBtu	BACT-PSD
AL-0300	Thyssenkrupp Stainless USA, LLC	3/25/2010	28.6	MMBtu/hr	LNB, FGR	0.0350	lb/MMBtu	BACT-PSD
OR-0050	Troutdale Energy Center, LLC	3/5/2014	39.8	MMBtu/hr	LNB, FGR	0.0350	lb/MMBtu	BACT-PSD
MI-0393	Ray Compressor Station	10/14/2010	12.25	MMBtu/hr	LNB	0.0351	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	14.34	MMBtu/hr	LNB, FGR	0.0353	lb/MMBtu	BACT-PSD
SC-0116	Cytec Carbon Fibers, LLC	4/30/2008	50	MMBtu/hr	None	0.0360	lb/MMBtu	BACT-PSD
OK-0137	Ponca City Refinery	2/9/2009	95	MMBtu/hr	Ultra LNB	0.0360	lb/MMBtu	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	40	MMBtu/hr	LNB	0.0360	lb/MMBtu	BACT-PSD
TX-0714	S R Bertron Electric Generating Station	12/19/2014	80	MMBtu/hr	LNB	0.0360	lb/MMBtu	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	LNB, FGR	0.0360	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	17.5	MMBtu/hr	LNB, FGR, GCP	0.0366	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	21	MMBtu/hr	LNB	0.0366	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	24.59	MMBtu/hr	LNB, FGR, GCP	0.0366	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	33.48	MMBtu/hr	LNB	0.0367	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	LNB, FGR	0.0400	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	LNB, FGR, GCP	0.0400	lb/MMBtu	BACT-PSD
LA-0295	Westlake Facility	7/12/2016	63	MMBtu/hr	GCP, FGR	0.0437	lb/MMBtu	BACT-PSD
OK-0148	Buffalo Creek Processing Plant	9/12/2012	11.04	MMBtu/hr	LNB	0.0450	lb/MMBtu	BACT-PSD
OH-0323	Titan Tire Corporation of Bryan	6/5/2008	50.4	MMBtu/hr	None	0.0476	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	16.7	MMBtu/hr	LNB	0.0490	lb/MMBtu	BACT-PSD
OR-0048	Carty Plant	12/29/2010	91	MMBtu/hr	LNB	0.0495	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	3/27/2013	217.5	MMBtu/hr	LNG, FGR, GCP	0.0500	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	LNB, FGR, GCP	0.0500	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	LNB, FGR, GCP	0.0500	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	LNB, GCP	0.0500	lb/MMBtu	BACT-PSD
OH-0315	New Steel International, Inc., Haverhill	5/6/2008	50.4	MMBtu/hr	LNB	0.0500	lb/MMBtu	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	3/9/2016	99.8	MMBtu/hr	LNB	0.0500	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	LNB, FGR	0.0500	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	229	MMBtu/hr	Ultra LNB, GCP, Clean fuels	0.0600	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	248	MMBtu/hr	Ultra LNB, GCP, Clean fuels	0.0600	lb/MMBtu	BACT-PSD
OK-0129	Chouteau Power Plant	1/23/2009	33.5	MMBtu/hr	LNB	0.0700	lb/MMBtu	BACT-PSD
TX-0576	Pipe Manufacturing Steel Mini Mill	4/19/2010	40	MMBtu/hr	GCP	0.1000	lb/MMBtu	BACT-PSD
TX-0772	Port of Beaumont Petroleum Transload Terminal (PBPTT)	11/6/2015	13.2	MMBtu/hr	None	0.1000	lb/MMBtu	BACT-PSD
TX-0732	Waste Heat Boiler No. 36	6/5/2015	100	MMBtu/hr	GCP	0.1100	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
OH-0310	American Municipal Power Generating Station	10/8/2009	150	MMBtu/hr	None	0.1333	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	2/23/2009	80	MMBtu/hr	LNB, GCP	0.2000	lb/MMBtu	BACT-PSD
AL-0249	Evonik Degussa Corporation	1/7/2010	212.6	MMBtu/hr	SNCR	0.2780	lb/MMBtu	BACT-PSD
SC-0122	Cytec Carbon Fibers, LLC	4/30/2008	50	MMBtu/hr	None	0.3600	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	SCR	7.0000	ppm	BACT-PSD
CA-1192	Avenal Energy Project	6/21/2011	37.4	MMBtu/hr	Ultra LNB, GCP, Clean fuels	9.0000	ppm	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	40	MMBtu/hr	None	9.0000	ppm	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	110	MMBtu/hr	None	9.0000	ppm	BACT-PSD
TX-0713	Tenaska Brownsville Generating Station	4/29/2014	90	MMBtu/hr	Ultra LNB	9.0000	ppm	BACT-PSD
TX-0712	Trinidad Generating Facility	11/20/2014	110	MMBtu/hr	Ultra LNB	9.0000	ppm	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	40	MMBtu/hr	None	9.0000	ppm	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	35	MMBtu/hr	None	9.0000	ppm	BACT-PSD
TN-0160	Volkswagen Group of America, Chattanooga Operations	10/10/2008	24	MMBtu/hr	LNB, FGR	30.0000	ppm	BACT-PSD
	Particulate Matter							
FL-0356	Okeechobee Clean Energy Center	3/9/2016	99.8	MMBtu/hr	Clean Fuels	10.0000	% opacity	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	40	MMBtu/hr	Clean Fuels	0.2000	gr/100 cf	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	35	MMBtu/hr	Clean Fuels	0.2000	gr/100 cf	BACT-PSD
CA-1192	Avenal Energy Project	6/21/2011	37.4	MMBtu/hr	Clean Fuels	0.3400	gr/100 cf	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	GCP	2.0000	gr/100 cf	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	GCP, Clean fuels	0.0018	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	0.0018	lb/MMBtu	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	7/19/2016	97.5	MMBtu/hr	Clean Fuels	0.0019	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	GCP, Clean fuels	0.0019	lb/MMBtu	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	3/10/2016	80	MMBtu/hr	Clean Fuels	0.0033	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	11/12/2008	93	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
MD-0041	CPV St. Charles	4/23/2014	93	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD
NY-0103	Cricket Valley Energy Center	2/3/2016	60	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD
LA-0240	Flopam Inc.	6/14/2010	25.1	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD
KS-0029	The Empire District Electric Company	7/14/2015	18.6	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
NY-0104	CPV Valley Energy Center	8/1/2013	73.5	MMBtu/hr	Clean Fuels	0.0063	lb/MMBtu	BACT-PSD
NY-0112	Westrock-Solvay LLC	11/2/2012			LNB, GCP	0.0070	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	110	MMBtu/hr	Clean Fuels	0.0073	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
AL-0249	Evonik Degussa Corporation	1/7/2010	212.6	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
MD-0046	Keys Energy Center	10/31/2014	93	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	40	MMBtu/hr	Clean Fuels	0.0075	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	2/23/2009	80	MMBtu/hr	None	0.0075	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
AL-0300	Thyssenkrupp Stainless USA, LLC	3/25/2010	28.6	MMBtu/hr	None	0.0076	lb/MMBtu	BACT-PSD
OH-0315	New Steel International, Inc., Haverhill	5/6/2008	50.4	MMBtu/hr	Clean Fuels	0.0077	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	4/14/2014	60.1	MMBtu/hr	None	0.0080	lb/MMBtu	BACT-PSD
WY-0075	Cheyenne Prairie Generating Station	7/16/2014	25.06	MMBtu/hr	GCP	0.0175	lb/MMBtu	BACT-PSD
MO-0079	American Energy Producers, Inc.	1/25/2008	190	MMBtu/hr	None	0.0236	lb/MMBtu	BACT-PSD
MO-0081	American Energy Producers, Inc.	1/22/2009	95	MMBtu/hr	None	0.0236	lb/MMBtu	BACT-PSD
PM10- Filterable								
OR-0048	Carty Plant	12/29/2010	91	MMBtu/hr	Clean Fuels	0.0024	lb/MMBtu	BACT-PSD
NJ-0080	Hess Newark Energy Center	11/1/2012	100	MMBtu/hr	Clean Fuels	0.0033	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	11/12/2008	93	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
FL-0318	Highlands Ethanol Facility	12/10/2009	198	MMBtu/hr	Fabric Filter*	0.0071	lb/MMBtu	BACT-PSD
OH-0310	American Municipal Power Generating Station	10/8/2009	150	MMBtu/hr	None	0.0072	lb/MMBtu	BACT-PSD
AL-0249	Evonik Degussa Corporation	1/7/2010	212.6	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	8/20/2009	21	MMBtu/hr	GCP	0.0076	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	5/5/2008	50.21	MMBtu/hr	GCP	0.0076	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0118	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0118	lb/MMBtu	BACT-PSD
PM10- Total								
CA-1192	Avenal Energy Project	6/21/2011	37.4	MMBtu/hr	Clean Fuels	0.3400	gr/100 cf	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	GCP	2.0000	gr/100 cf	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
MD-0041	CPV St. Charles	4/23/2014	93	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD
LA-0240	Flopam Inc.	6/14/2010	25.1	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	3/10/2016	80	MMBtu/hr	Clean Fuels	0.0050	lb/MMBtu	BACT-PSD
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
MA-0039	Salem Harbor Station Redevelopment	1/30/2014	80	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
KS-0029	The Empire District Electric Company	7/14/2015	18.6	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	7/19/2016	97.5	MMBtu/hr	Clean Fuels	0.0050	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	2/23/2009	80	MMBtu/hr	None	0.0063	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	229	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	248	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	110	MMBtu/hr	Clean Fuels	0.0073	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MD-0046	Keys Energy Center	10/31/2014	93	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	40	MMBtu/hr	Clean Fuels	0.0075	lb/MMBtu	BACT-PSD
TX-0576	Pipe Manufacturing Steel Mini Mill	4/19/2010	40	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
OH-0352	Oregon Clean Energy Center	6/18/2013	99	MMBtu/hr	Clean Fuels	0.0080	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	3/27/2013	217.5	MMBtu/hr	GCP	0.0089	lb/MMBtu	BACT-PSD
OK-0156	Northstar Agri Ind Enid	7/31/2013	95	MMBtu/hr	GCP	0.0130	lb/MMBtu	BACT-PSD
MO-0081	American Energy Producers, Inc.	1/22/2009	95	MMBtu/hr	None	0.0164	lb/MMBtu	BACT-PSD
MO-0079	American Energy Producers, Inc.	1/25/2008	190	MMBtu/hr	None	0.0164	lb/MMBtu	BACT-PSD
MA-0037	Central Heating Plant: Amherst Campus	10/29/2008	162	MMBtu/hr	None	0.0200	lb/MMBtu	BACT-PSD
PM2.5- Total								
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD
AL-0249	Evonik Degussa Corporation	1/7/2010	212.6	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	40	MMBtu/hr	None	0.2000	gr/100 cf	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	3/11/2010	35	MMBtu/hr	None	0.2000	gr/100 cf	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	GCP	2.0000	gr/100 cf	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	67	MMBtu/hr	GCP, Clean fuels	0.0005	lb/MMBtu	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	11/21/2014	100	MMBtu/hr	GCP, Clean fuels	0.0050	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	3/10/2016	80	MMBtu/hr	Clean Fuels	0.0050	lb/MMBtu	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	1/30/2014	80	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
KS-0029	The Empire District Electric Company	7/14/2015	18.6	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	7/19/2016	97.5	MMBtu/hr	Clean Fuels	0.0050	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	229	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	248	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	GCP, Clean fuels	0.0070	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	110	MMBtu/hr	Clean Fuels	0.0073	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	0.0074	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
OK-0148	Buffalo Creek Processing Plant	9/12/2012	11.04	MMBtu/hr	None	0.0075	lb/MMBtu	BACT-PSD
MI-0427	Filer City Station	11/17/2017	182	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MD-0045	Mattawoman Energy Center	11/13/2015	42	MMBtu/hr	GCP, Clean fuels	0.0075	lb/MMBtu	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	10/18/2011	40	MMBtu/hr	Clean Fuels	0.0075	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	3/27/2013	217.5	MMBtu/hr	GCP	0.0089	lb/MMBtu	BACT-PSD
OK-0156	Northstar Agri Ind Enid	7/31/2013	95	MMBtu/hr	GCP	0.0126	lb/MMBtu	BACT-PSD
Volatile Organic Compounds								
TX-0813	Odessa Petrochemical Plant	11/22/2016	223	MMBtu/hr	GCP	0.0005	lb/MMBtu	BACT-PSD
MO-0079	American Energy Producers, Inc.	1/25/2008	190	MMBtu/hr	GCP	0.0010	lb/MMBtu	BACT-PSD
MI-0389	Karn Weadock Generating Complex	12/29/2009	220	MMBtu/hr	GCP	0.0013	lb/MMBtu	BACT-PSD
FL-0318	Highlands Ethanol Facility	12/10/2009	198	MMBtu/hr	None	0.0015	lb/MMBtu	BACT-PSD
WY-0075	Cheyenne Prairie Generating Station	7/16/2014	25.06	MMBtu/hr	GCP	0.0017	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	5/5/2008	50.21	MMBtu/hr	GCP, Clean fuels	0.0026	lb/MMBtu	BACT-PSD
TX-0681	Olefins Plant	8/8/2014			GCP	0.0030	lb/MMBtu	BACT-PSD
FL-0335	Suwannee Mill	9/5/2012	46	MMBtu/hr	GCP	0.0030	lb/MMBtu	BACT-PSD
LA-0295	Westlake Facility	7/12/2016	63	MMBtu/hr	Ox Cat, GCP	0.0033	lb/MMBtu	BACT-PSD
VA-0327	Perdue Grain And Oilseed, LLC	7/12/2017	27	MMBtu/hr	None	0.0037	lb/MMBtu	BACT-PSD
AR-0121	El Dorado Chemical Company	11/18/2013	240	MMBtu/hr	GCP	0.0040	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	1/4/2017	182	MMBtu/hr	GCP	0.0040	lb/MMBtu	BACT-PSD
MI-0393	Ray Compressor Station	10/14/2010	12.25	MMBtu/hr	None	0.0041	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	4/14/2014	60.1	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
MI-0406	Renaissance Power LLC	11/1/2013	40	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	12/3/2012	80	MMBtu/hr	GCP	0.0050	lb/MMBtu	BACT-PSD
IN-0239	Subaru of Indiana Automotive, Inc.	2/18/2016	38	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD

Table D-2 - RBLC Results for Auxiliary Boiler

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
OR-0050	Troutdale Energy Center, LLC	3/5/2014	39.8	MMBtu/hr	LNB, FGR	0.0050	lb/MMBtu	BACT-PSD
OH-0310	American Municipal Power Generating Station	10/8/2009	150	MMBtu/hr	None	0.0052	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	3/23/2017	218.6	MMBtu/hr	GCP	0.0052	lb/MMBtu	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0052	lb/MMBtu	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	6/4/2014	218.6	MMBtu/hr	GCP	0.0052	lb/MMBtu	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	9/25/2013	218	MMBtu/hr	GCP	0.0052	lb/MMBtu	BACT-PSD
OH-0323	Titan Tire Corporation of Bryan	6/5/2008	50.4	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
OH-0350	Republic Steel	7/18/2012	65	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	3/27/2013	217.5	MMBtu/hr	GCP, FGR	0.0054	lb/MMBtu	BACT-PSD
AL-0312	Belk Chip-N-Saw Facility	5/26/2016	60	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	24.5	MMBtu/hr	GCP, Clean fuels	0.0054	lb/MMBtu	BACT-PSD
AR-0140	Big River Steel LLC	9/18/2013	51.2	MMBtu/hr	GCP, Clean fuels	0.0054	lb/MMBtu	BACT-PSD
OK-0148	Buffalo Creek Processing Plant	9/12/2012	11.04	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	229	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
LA-0314	Indorama Lake Charles Facility	8/3/2016	248	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	50	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	1/6/2015	243	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
AL-0282	Lenzing Fibers, Inc.	1/22/2014	100	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
TX-0576	Pipe Manufacturing Steel Mini Mill	4/19/2010	40	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
SC-0160	US8 Facility	12/13/2012	33.6	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
IA-0096	Verasun Charles City, LLC	11/18/2008	50	MMBtu/hr	None	0.0054	lb/MMBtu	BACT-PSD
MO-0082	Archer Daniels Midland-Mexico	10/5/2010	85.6	MMBtu/hr	GCP	0.0055	lb/MMBtu	BACT-PSD
AL-0286	Mount Vernon Mill	3/25/2010	70	MMBtu/hr	None	0.0055	lb/MMBtu	BACT-PSD
AL-0300	Thyssenkrupp Stainless USA, LLC	3/25/2010	28.6	MMBtu/hr	None	0.0055	lb/MMBtu	BACT-PSD
OH-0315	New Steel International, Inc., Haverhill	5/6/2008	50.4	MMBtu/hr	None	0.0056	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0059	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	17.5	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT-PSD
AL-0307	Alloys Plant	10/9/2015	24.59	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	11/21/2014	100	MMBtu/hr	GCP, Clean fuels	0.0060	lb/MMBtu	BACT-PSD
OK-0156	Northstar Agri Ind Enid	7/31/2013	95	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT-PSD
OH-0352	Oregon Clean Energy Center	6/18/2013	99	MMBtu/hr	GCP	0.0060	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	2/23/2009	80	MMBtu/hr	None	0.0063	lb/MMBtu	BACT-PSD
LA-0248	Direct Reduction Iron Plant	1/27/2011	201	MMBtu/hr	GCP	0.0078	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	55	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT-PSD
MI-0412	Holland Board of Public Works - East 5th Street	12/4/2013	95	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT-PSD
MI-0424	Holland Board of Public Works - East 5th Street	12/5/2016	83.5	MMBtu/hr	GCP	0.0080	lb/MMBtu	BACT-PSD
MI-0410	Thetford Generating Station	7/25/2013	100	MMBtu/hr	GCP, Clean fuels	0.0080	lb/MMBtu	BACT-PSD
OK-0129	Chouteau Power Plant	1/23/2009	33.5	MMBtu/hr	GCP	0.0161	lb/MMBtu	BACT-PSD
MO-0081	American Energy Producers, Inc.	1/22/2009	95	MMBtu/hr	None	0.0164	lb/MMBtu	BACT-PSD

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Nitrogen Dioxide								
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		0.011	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP/LNB	0.095	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	SCR/CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP/LNB	0.1	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.097	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.095	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		SCR/CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.08	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP/LNB	0.035	LB/MMBTU	BACT
AR-0167	LION OIL COMPANY	12/01/2020	75	MMBtu/hr	Ultra-LNB/GCP	3.5	LB/HR	BACT
AR-0167	LION OIL COMPANY	12/01/2020	56	MMBtu/hr	GCP	2.8	LB/HR	BACT
AR-0167	LION OIL COMPANY	12/01/2020	70	MMBtu/hr		12.7	LB/HR	BACT
AR-0167	LION OIL COMPANY	12/01/2020	50	MMBtu/hr	GCP	5.3	LB/HR	BACT
AR-0167	LION OIL COMPANY	12/01/2020	142.2	MMBtu/hr	Ultra-LNB/GCP	6.5	LB/HR	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP/LNB	0.1	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP/LNB	0.1	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	CBF/GCP/LNB	0.1	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP/LNB	0.1	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		GCP/Energy efficient burners/CBF	0.05	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	LNB/SCR/SNCR	0.0075	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	LNB	0.035	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		LNB	0.0915	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		LNB	0.035	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		LNB/SCR/SNCR	0.0075	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	12/31/2018	96	mmBtu/hr	Ultra-LNB/FGR/GCP	0.01	LB/MMBTU	LAER
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	LNB/GCP	158	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	LNB/GCP	81.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	LNB/GCP	35	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	LNB/GCP	7.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	LNB/GCP	70	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	LNB/GCP	70	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		LNB	0.06	LB/MMBTU	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	SCR/LNB	14.41	LB/H	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	LNB or FGR/GCP	30	PPM	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	GCP/LNB	0.036	LB/MMBTU	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	LNB or FGR/GCP	30	PPM	BACT
OH-0379	PETMIN USA INCORPORATED	02/06/2019	0		Direct Evacuation Control	1.4	LB/T	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/LNB/GCP	6.16	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/LNB/GCP	7.84	LB/H	BACT
TX-0851	RIO BRAVO PIPELINE FACILITY	12/17/2018	71.3	MMBTU/HR	LNB/GCP	0.162	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		SCR/CEMS	0.015	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	100	MMBtu	GCP/LNB	0.04	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		LNB	0.06	LB/MMBTU	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP/LNB	43.8	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP/LNB	68.8	LB/HR	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Carbon Monoxide								
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		0.037	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0167	LION OIL COMPANY	12/01/2020	142.2	MMBtu/hr	GCP	7.4	LB/HR	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP	0.0824	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	0.084	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	0.075	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.084	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.084	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	12/31/2018	96	mmBtu/hr	GCP	0.037	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	GCP	84	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	61	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	GCP	84	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		GCP	0.037	LB/MMBTU	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	GCP/OxCat	26.21	LB/H	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	GCP	50	PPM	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	GCP	0.037	LB/MMBTU	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	GCP	50	PPM	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/baffle burners/GCP	6.16	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/baffle burners/GCP	7.84	LB/H	BACT
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	05/21/2019	0		Work Practice Standards	0.0375	LB/MMBTU	BACT
TX-0851	RIO BRAVO PIPELINE FACILITY	12/17/2018	71.3	MMBTU/HR	CBF/GCP	0.082	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		GCP/proper design	50	PPMVD	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	100	MMBtu	GCP/proper design	50	PPMVD	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		CBF/GCP	0.06	LB/MMBTU	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		CBF/GCP	58.3	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP	45.8	LB/HR	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
				Volatile Organic Compounds				
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		0.004	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP	0.0054	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		GCP/Energy efficient burners/CBF	0.0054	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	0.0055	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	0.0026	LB/HR	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0055	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0055	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		GCP	4.02	LB/H	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	OxCat/GCP	13.37	LB/H	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	GCP	0.5	LB/H	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	GCP	0.0054	LB/MMBTU	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	GCP	0.3	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/GCP	0.48	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/GCP	0.62	LB/H	BACT
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	05/21/2019	0		Work Practice Standards	0.0054	LB/MMBTU	BACT
TX-0851	RIO BRAVO PIPELINE FACILITY	12/17/2018	71.3	MMBTU/HR	CBF/GCP	0.0054	LB/MMBTU	BACT
TX-0877	SWEENY REFINERY	01/08/2020	0		CBF/GCP	0.0054	LB/MMBTU	LAER
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		GCP/proper design	0.0054	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	100	MMBtu	GCP/proper design	0.0054	LB/MMBTU	BACT
*WI-0289	GEORGIA-PACIFIC CONSUMER PRODUCTS LLC	04/01/2019	95	mmBTU/hr	GCP	0.0055	LB/MMBTU	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
				PM_{10} (total)				
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	6.8	X10^-4 LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0012	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0007	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		Mist eliminator/GCP	0.003	GR/DSCF	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		GCP/Energy efficient burners/CBF	0.0075	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0076	GR/DSCF	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		Wet Scrubber System with mist eliminator	0.0013	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		CBF/GCP	0.03	LB/H	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	CBF/GCP	0.61	LB/H	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	GCP	0.74	LB/H	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	CBF/GCP	7.6	LB/MMSCF	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	GCP	0.74	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	02/06/2019	0		Control Efficiency	0.074	LB/T	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/GCP	0.88	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/GCP	1.12	LB/H	BACT
TX-0851	RIO BRAVO PIPELINE FACILITY	12/17/2018	71.3	MMBTU/HR	CBF/GCP	0.0075	LB/MMBTU	BACT
*VA-0333	NORFOLK NAVAL SHIPYARD	12/09/2020	76.6	MMBtu/hr		0.0078	LB	BACT
				PM_{10} (filterable only)				
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		0.0075	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP	9.38	X10^-4 LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	CBF/GCP	0.0012	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	100	MMBtu	CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		CBF/GCP	0.0075	LB/MMBTU	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
				$PM_{2.5}$ (total)				
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP	9.38	X10^-4 LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	6.8	X10^-4 LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	CBF/GCP	0.0012	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0012	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0007	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP	0.013	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		Mist eliminator/GCP	0.03	GR/DSCF	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		GCP/Energy efficient burners/CBF	0.0075	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	0.0076	GR/DSCF	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		Wet Scrubber System with mist eliminator	0.0012	GR/DSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		CBF/GCP	0.03	LB/H	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	CBF/GCP	0.61	LB/H	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	GCP	0.74	LB/H	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	CBF/GCP	7.6	LB/MMSCF	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	GCP	0.4	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	02/06/2019	0		Control Efficiency	0.0061	LB/T	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/GCP	0.88	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/GCP	1.12	LB/H	BACT
TX-0851	RIO BRAVO PIPELINE FACILITY	12/17/2018	71.3	MMBTU/HR	CBF/GCP	0.0075	LB/MMBTU	BACT
*VA-0333	NORFOLK NAVAL SHIPYARD	12/09/2020	76.6	MMBtu/hr		0.0078	LB	BACT
				$PM_{2.5}$ (filterable only)				
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		0.0075	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	100	MMBtu	CBF/GCP	0.0075	LB/MMBTU	BACT
TX-0888	ORANGE POLYETHYLENE PLANT	04/23/2020	0		CBF/GCP	0.0075	LB/MMBTU	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
				Greenhouse Gases - CO_2				
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	GCP	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Minimum Boiler Efficiency	117	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	GCP	117	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	GCP	117	LB/MMBTU	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	GCP	117	LB/MMBTU	BACT
				Greenhouse Gases - CO_2 equivalents				
*AL-0328	PLANT BARRY	11/09/2020	90.5	MMBtu/hr		46416	TPY	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	121	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	121	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	121	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	121	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	12/31/2018	96	mmBtu/hr	GCP	11250	TONS/YEAR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	54	MMBtu/hr	GCP	27991	TON/YR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	60	MMBtu/hr, combined	GCP	31101	TON/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	26125	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	94	MMBtu/hr	GCP	48725	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	104.3	MMBtu/hr	GCP	54065	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	65.5	MMBtu/hr	GCP	33952	TONS/YR	BACT
LA-0364	FG LA COMPLEX	01/06/2020	0		GCP	5858	TONS/YR	BACT
LA-0364	FG LA COMPLEX	01/06/2020	94	mm btu/h	CBF/energy-efficient design options/GCP	455475	T/YR	BACT
MI-0441	LBWL--ERICKSON STATION	12/21/2018	99	MMBTU/H	CBF/GCP/energy efficiency measures	50776	T/YR	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	80	MMBTU/H	Energy efficiency	41031	T/YR	BACT
MI-0447	LBWL--ERICKSON STATION	01/07/2021	50	MMBTU/H	CBF/GCP/energy efficiency measures	25644	T/YR	BACT
OH-0379	PETMIN USA INCORPORATED	02/06/2019	0		GCP	186.41	LB/T	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	88	MMBTU/H	CBF/energy efficient design	10283.06	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	112	MMBTU/H	CBF/energy efficient design	13087.2	LB/H	BACT
*VA-0333	NORFOLK NAVAL SHIPYARD	12/09/2020	76.6	MMBtu/hr		117.1	LB	BACT
				Sulfuric Acid Mist				
IL-0130	JACKSON ENERGY CENTER	12/31/2018	96	mmBtu/hr	GCP	0.1	POUNDS/HOUR	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-2 Addendum: RBLC Results for Auxiliary Boiler
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Opacity								
AR-0155	BIG RIVER STEEL LLC	11/07/2018	88.7	MMBTU/HR	CBF/GCP	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	0		CBF/GCP	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	CBF/GCP	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	78.2	MMBTU/HR	CBF/GCP	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	11/07/2018	85.15	MMBTU/HR	CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	04/05/2019	0		CBF/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	117.9	MMBtu/hr	CBF/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	58	MMBtu/hr	CBF/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	66	MMBtu/hr	CBF/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	64	MMBtu/hr	CBF/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		Mist eliminator/GCP	5	%	BACT
AR-0168	BIG RIVER STEEL LLC	03/17/2021	0		GCP/Energy efficient burners/CBF	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	128	MMBTU/hr	GCP	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	02/14/2019	50.4	MMBTU/hr	GCP	5	%	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	5	%	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		GCP	5	%	BACT
*AR-0172	NUCOR STEEL ARKANSAS	09/01/2021	0		Wet Scrubber System with mist eliminator	10	%	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0			15	%	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0			15	%	BACT

(a) OxCat = oxidation catalyst, SCR = selective catalytic reduction, LNB = low-NOx burners, GCP = good combustion practices, CBF = clean burning fuels, SNCR = selective, noncatalytic reduction, CEMS = continuous emission monitoring system

Table D-3 Removed
Cooling Tower removed from Application

Table D-4 - RBLC Results for Natural Gas Heater

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Carbon Monoxide									
OK-0168	Seminole Generating Station	O G AND E	5/5/2015	40.4	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	0.0194	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.0365	lb/MMBtu	BACT-PSD
IN-0285	Whiting Clean Energy, Inc.	WHITING CLEAN ENERGY, INC.	8/2/2017	0		None	0.0380	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	INTERSTATE POWER AND LIGHT	4/14/2014	13.32	MMBtu/hr	None	0.0410	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr	GCP	0.0500	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	35	MMBtu/hr	GCP	0.0560	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	20.89	MMBtu/hr	None	0.0799	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	1.7	MMBtu/hr	None	0.0800	lb/MMBtu	BACT-PSD
MS-0092	Emberclear GTL MS	EMBERCLEAR GTL MS LLC	5/8/2014	12	MMBtu/hr	None	0.0800	lb/MMBtu	BACT-PSD
MS-0092	Emberclear GTL MS	EMBERCLEAR GTL MS LLC	5/8/2014	13	MMBtu/hr	None	0.0800	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	75	MMBtu/hr	GCP	0.0800	lb/MMBtu	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP	0.0820	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP	0.0820	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0822	lb/MMBtu	BACT-PSD
LA-0311	Donaldsonville Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/15/2013	94.5	MMBtu/hr	GCP	0.0823	lb/MMBtu	BACT-PSD
OK-0153	Rose Valley Plant	SEMGAS LP	3/1/2013	17.4	MMBtu/hr	GCP	0.0824	lb/MMBtu	BACT-PSD
OK-0153	Rose Valley Plant	SEMGAS LP	3/1/2013	5.61	MMBtu/hr	GCP	0.0824	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	56.9	MMBtu/hr	GCP	0.0824	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	34.2	MMBtu/hr	GCP	0.0825	lb/MMBtu	BACT-PSD
OK-0134	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	GCP	0.0825	lb/MMBtu	BACT-PSD
OK-0134	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	GCP	0.0825	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	GCP	0.0825	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	0.0840	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	NUCOR STEEL	5/5/2008	58	MMBtu/hr	GCP, clean fuels	0.0840	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.1108	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.1108	lb/MMBtu	BACT-PSD

Table D-4 - RBLC Results for Natural Gas Heater

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
Greenhouse Gases - Carbon Dioxide									
LA-0311	Donaldsonville Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/15/2013	94.5	MMBtu/hr	GCP, clean fuels	117	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	117	lb/MMBtu	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	117	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide Equivalents									
LA-0311	Donaldsonville Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/15/2013	94.5	MMBtu/hr	GCP, clean fuels	117	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	120	lb/MMBtu	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	345	tpy	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr	GCP	1,738	tpy	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	1,934	tpy	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	1,934	tpy	BACT-PSD
IA-0107	Marshalltown Generating Station	INTERSTATE POWER AND LIGHT	4/14/2014	13.32	MMBtu/hr	None	6,860	tpy	BACT-PSD
IA-0107	Marshalltown Generating Station	INTERSTATE POWER AND LIGHT	4/14/2014	13.32	MMBtu/hr	None	6,860	tpy	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP, clean fuels	13,848	tpy	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP, clean fuels	17,438	tpy	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP, clean fuels	19,490	tpy	BACT-PSD
OK-0164	Midwest City Air Depot	TINKER AIR FORCE BASE LOGISTICS CENTER	1/8/2015	0	MMBtu/hr	GCP, clean fuels	153,716	tpy	BACT-PSD
Nitrogen Oxides									
IA-0107	Marshalltown Generating Station	INTERSTATE POWER AND LIGHT	4/14/2014	13.32	MMBtu/hr	None	0.0130	lb/MMBtu	BACT-PSD
AK-0071	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION, INC.	12/20/2010	12.5	MMBtu/hr	LNB, FGR	0.0305	lb/MMBtu	BACT-PSD
OK-0153	Rose Valley Plant	SEMGAS LP	3/1/2013	5.61	MMBtu/hr	LNB	0.0450	lb/MMBtu	BACT-PSD
OK-0153	Rose Valley Plant	SEMGAS LP	3/1/2013	17.4	MMBtu/hr	LNB	0.0450	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	75	MMBtu/hr	LNB	0.0476	lb/MMBtu	BACT-PSD
OK-0134	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	LNB, GCP	0.0490	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	LNB, GCP	0.0490	lb/MMBtu	BACT-PSD
OR-0048	Carty Plant	PORTLAND GENERAL ELECTRIC	12/29/2010	91	MMBtu/hr	LNB	0.0495	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	LNB, GCP	0.0500	lb/MMBtu	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	LNB, GCP	0.0500	lb/MMBtu	BACT-PSD
IN-0285	Whiting Clean Energy, Inc.	WHITING CLEAN ENERGY, INC.	8/2/2017	0		None	0.0500	lb/MMBtu	BACT-PSD

Table D-4 - RBLC Results for Natural Gas Heater

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
LA-0244	Lake Charles Chemical Complex - Lab Unit	SASOL NORTH AMERICA, INC.	11/29/2010	87.3	MMBtu/hr	LNB	0.0819	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	20.89	MMBtu/hr	None	0.0953	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	34.2	MMBtu/hr	GCP	0.0980	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	56.9	MMBtu/hr	GCP	0.0981	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0981	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	0.1000	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	1.7	MMBtu/hr	None	0.1000	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	NUCOR STEEL	5/5/2008	58	MMBtu/hr	LNB	0.1000	lb/MMBtu	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FLORIDA POWER & LIGHT	3/9/2016	10	MMBtu/hr	GCP	0.1000	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	35	MMBtu/hr	GCP	0.1100	lb/MMBtu	BACT-PSD
LA-0244	Lake Charles Chemical Complex - Lab Unit	SASOL NORTH AMERICA, INC.	11/29/2010	21	MMBtu/hr	LNB	0.1290	lb/MMBtu	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	18.8	MMBtu/hr	None	0.1436	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.1486	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.1486	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.1802	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr	GCP	0.2466	lb/MMBtu	BACT-PSD
Particulate Matter									
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.0019	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0020	lb/MMBtu	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	0.0024	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	1.7	MMBtu/hr	None	0.0070	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.0070	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	20.89	MMBtu/hr	None	0.0072	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	75	MMBtu/hr	None	0.0072	lb/MMBtu	BACT-PSD
AK-0071	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION, INC.	12/20/2010	12.5	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD

Table D-4 - RBLC Results for Natural Gas Heater

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
OK-0135	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	None	0.0075	lb/MMBtu	BACT-PSD
IA-0107	Marshalltown Generating Station	INTERSTATE POWER AND LIGHT	4/14/2014	13.32	MMBtu/hr	None	0.0080	lb/MMBtu	BACT-PSD
			PM10						
OR-0048	Carty Plant	PORTLAND GENERAL ELECTRIC	12/29/2010	91	MMBtu/hr	Clean fuels	0.0024	lb/MMBtu	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	1.7	MMBtu/hr	None	0.0070	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	20.89	MMBtu/hr	None	0.0072	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	75	MMBtu/hr	None	0.0072	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	NUCOR STEEL	5/5/2008	58	MMBtu/hr	GCP, clean fuels	0.0076	lb/MMBtu	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP	0.0005	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP	0.0005	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	35	MMBtu/hr	GCP	0.0009	lb/MMBtu	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	0.0024	lb/MMBtu	BACT-PSD
AK-0071	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION, INC.	12/20/2010	12.5	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	34.2	MMBtu/hr	GCP	0.0073	lb/MMBtu	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	56.9	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
OK-0134	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	Clean fuels	0.0075	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	None	0.0075	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	0.0076	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr	GCP	0.0089	lb/MMBtu	BACT-PSD
LA-0244	Lake Charles Chemical Complex - Lab Unit	SASOL NORTH AMERICA, INC.	11/29/2010	87.3	MMBtu/hr	None	0.0099	lb/MMBtu	BACT-PSD
LA-0244	Lake Charles Chemical Complex - Lab Unit	SASOL NORTH AMERICA, INC.	11/29/2010	21	MMBtu/hr	None	0.0100	lb/MMBtu	BACT-PSD
			PM2.5						
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP	0.0004	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP	0.0004	lb/MMBtu	BACT-PSD

Table D-4 - RBLC Results for Natural Gas Heater

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	Emission Limit	Units	Type
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	0.0024	lb/MMBtu	BACT-PSD
AK-0071	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION, INC.	12/20/2010	12.5	MMBtu/hr	GCP	0.0072	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0074	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.0075	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	0.0076	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr	GCP	0.0089	lb/MMBtu	BACT-PSD
Volatile Organic Compounds									
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013	58.8	MMBtu/hr	GCP, clean fuels	0.0014	lb/MMBtu	BACT-PSD
FL-0364	Seminole Generating Station	SEMINOLE ELECTRIC COOPERATIVE, INC.	3/21/2018	9.9	MMBtu/hr	None	0.0050	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	75	MMBtu/hr	GCP	0.0052	lb/MMBtu	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	20.89	MMBtu/hr	None	0.0053	lb/MMBtu	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	18.8	MMBtu/hr	None	0.0053	lb/MMBtu	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	34	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	38	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	70	MMBtu/hr	GCP	0.0054	lb/MMBtu	BACT-PSD
OK-0173	CMC Steel Oklahoma	COMMERCIAL METALS COMPANY	1/19/2016	0		Clean fuels	0.0055	lb/MMBtu	BACT-PSD
SC-0112	Nucor Steel - Berkeley	NUCOR STEEL	5/5/2008	58	MMBtu/hr	GCP, clean fuels	0.0055	lb/MMBtu	BACT-PSD
OK-0134	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	GCP	0.0055	lb/MMBtu	BACT-PSD
OK-0135	Pryor Plant Chemical	PRYOR PLANT CHEMICAL COMPANY	2/23/2009	20	MMBtu/hr	None	0.0055	lb/MMBtu	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	27	MMBtu/hr	GCP	0.0056	lb/MMBtu	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	59.4	MMBtu/hr		0.0064	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	3.7	MMBtu/hr	GCP	0.0081	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	3.7	MMBtu/hr	GCP	0.0081	lb/MMBtu	BACT-PSD
OK-0164	Midwest City Air Depot	TINKER AIR FORCE BASE LOGISTICS CENTER	1/8/2015	0	MMBtu/hr	GCP, clean fuels	7.1	tpy	BACT-PSD

Table D-4 Addendum: RBLC Results for Natural Gas Heater
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
				Nitrogen Oxides					
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	LNB/GCP	0.036	LB/MMBTU	BACT
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	09/21/2021	10	MMBtu/hr		0.011	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		LNB/CBF/GCP	0.095	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.097	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.095	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		SCR/LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.08	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		LNB/CBF/GCP	0.035	LB/MMBTU	BACT
AR-0167	LION OIL COMPANY	DELEK US	12/01/2020	40	MMBtu/hr	Ultra-LNB/GCP	1.9	LB/HR	BACT
AR-0167	LION OIL COMPANY	DELEK US	12/01/2020	50	MMBtu/hr	GCP	5.3	LB/HR	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		LNB	0.063	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	LNB	0.1	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	LNB	0.035	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	LNB	0.1	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		LNB	0.035	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	LNB/GCP	70	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	LNB/GCP	50	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	100	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	LNB/GCP	35	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	LNB/GCP	50	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	LNB/GCP	50	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	LNB/GCP	50	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	LNB/GCP	70	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		LNB	0.06	LB/MMBTU	BACT
LA-0377	TOKAI ADDIS FACILITY	TOKAI CARBON CB LTD.	05/27/2020	12	MW	LNB/GCP	0.08	LB/MMBTU	BACT
LA-0377	TOKAI ADDIS FACILITY	TOKAI CARBON CB LTD.	05/27/2020	5.88	MM scf/h	LNB/FGR/GCP	300	PPM	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	LNB/GCP	0.05	LB/MMBTU	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	LNB/GCP	0.036	LB/MMBTU	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	GCP	1.32	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	LNB/FGR/GCP	30	PPM	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15.17	MMBTU/H	LNB/CBF/GCP	0.634	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15	MMBTU/H	GCP/CBF	2.12	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	GCP/CBF	0.12	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	GCP/CBF	1.6	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	GCP/CBF	0.95	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	LNB/CBF/GCP	2.1	LB/H	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		LNB/GCP	43.8	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		LNB/GCP	68.8	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	1.5	mmBTU/hr	GCP	0.1	LB/MMBTU	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
Carbon Monoxide									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	GCP/CBF	0.087	LB/MMBTU	BACT
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	09/21/2021	10	MMBtu/hr		0.08	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0824	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	0.084	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	0.084	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	0.075	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	0.084	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	0.084	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	13	mmBtu/hour	GCP	0.08	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	GCP	84	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	61	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	GCP	84	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	GCP	84	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		GCP	0.037	LB/MMBTU	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	GCP	0.08	LB/MMBTU	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	GCP	0.037	LB/MMBTU	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	GCP	1.11	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	GCP	50	PPM	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	GCP/CBF	0.02	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	GCP/CBF	0.32	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	GCP/CBF	0.19	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	CBF/baffle burners/GCP	2.1	LB/H	BACT
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	CANFOR SOUTHERN PINE	05/21/2019	0		Work Practice Standards	0.0375	LB/MMBTU	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP	58.3	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP	45.8	LB/HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	1.5	mmBTU/hr	GCP	0.082	LB/MMBTU	BACT
Volatile Organic Compounds									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	GCP/CBF	0.0057	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0054	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	0.0026	LB/HR	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	0.0055	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	0.0055	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	GCP	5.5	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

Table D-4 Addendum: RBLC Results for Natural Gas Heater
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	GCP	5.5	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	GCP	5.5	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		GCP	4.02	LB/H	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	GCP	0.005	LB/MMBTU	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	GCP	0.025	LB/MMBTU	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	GCP	0.07	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	GCP	0.3	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	GCP/CBF	0.01	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	GCP/CBF	0.09	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	GCP/CBF	0.05	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	GCP/CBF	0.17	LB/H	BACT
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	CANFOR SOUTHERN PINE	05/21/2019	0		Work Practice Standards	0.0054	LB/MMBTU	BACT
*WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	GREEN BAY PACKAGING INC. â€“MILL DIVISION	04/01/2019	20	mmBTU/hr	LNB/GCP	0.0055	LB/MMBTU	BACT
Greenhouse Gases -Carbon Dioxide Equivalents									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	GCP/CBF	117.1	LB/MMBTU	BACT
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	09/21/2021	10	MMBtu/hr		117.1	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	121	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	121	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	121	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	121	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	121	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	13	mmBtu/hour	GCP	6700	TONS/YEAR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	GCP	20734	TON/YR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	GCP	11404	TON/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	20734	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	26125	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	GCP	12675	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	GCP	11922	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	GCP	15032	TONS/YR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	GCP	30	TONS/YR	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		CBF/energy efficient design/GCP	5858	TONS/YR	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	GCP/CBF	12822	T/YR	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	Energy Efficiency	3590	T/YR	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	Energy Efficiency Measures/CBF	13848	T/YR	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	Energy Efficiency Measures/CBF/GCP	25644	T/YR	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15.17	MMBTU/H	GCP/CBF	1784	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15	MMBTU/H	GCP/CBF	1764	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	CBF/Energy Efficient Design	140.22	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	CBF/Energy Efficient Design	1869.65	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	CBF/Energy Efficient Design	1110.1	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	CBF/Energy Efficient Design	3505.59	LB/H	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

Table D-4 Addendum: RBLC Results for Natural Gas Heater
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
				PM_{10} (total)					
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	GCP/CBF	0.0079	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	6.8	X10^-4 LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0012	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0007	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	0.0076	GR/DSCF	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		Wet Scrubber System with mist eliminator	0.0013	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		GCP/CBF	0.03	LB/H	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	GCP	0.008	LB/MMBTU	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	GCP/CBF	7.6	LB/MMSCF	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	GCP	0.1	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	GCP	0.74	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15.17	MMBTU/H	GCP/CBF	0.113	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15	MMBTU/H	GCP/CBF	0.112	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	GCP/CBF	0.004	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	GCP/CBF	0.05	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	GCP/CBF	0.03	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	GCP/CBF	0.3	LB/H	BACT
				PM_{10} (filterable only)					
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	09/21/2021	10	MMBtu/hr		0.008	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

Table D-4 Addendum: RBLC Results for Natural Gas Heater
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
				$PM_{2.5}$ (total)					
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	32	MMBtu/hr	GCP/CBF	0.0079	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	6.8	X10^-4 LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0012	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0019	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0007	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	0.0076	LB/MMBTU	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	0.0076	LB/MMBTU	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	0.0076	GR/DSCF	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		Wet Scrubber System with mist eliminator	0.0012	GR/DSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	40	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	22	MMBtu/hr, combined	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	40	MMBtu/hr, total	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	50.4	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	18	MMBtu/hr, each	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	23	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	14.5	MMBtu/hr, each	GCP	7.6	LB/MMSCF	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	3	MMBtu/hr	GCP	7.6	LB/MMSCF	BACT
LA-0364	FG LA COMPLEX	FG LA LLC	01/06/2020	0		GCP/CBF	0.03	LB/H	BACT
MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	05/22/2019	25	MMBTU/H	GCP	0.008	LB/MMBTU	BACT
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	08/21/2019	7	MMBTU/H	GCP/CBF	7.6	LB/MMSCF	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	27	MMBTU/H	GCP	0.1	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	50	MMBTU/H	GCP	0.4	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15.17	MMBTU/H	GCP/CBF	0.113	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	15	MMBTU/H	GCP/CBF	0.112	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	1.2	MMBTU/H	GCP/CBF	0.004	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	16	MMBTU/H	GCP/CBF	0.05	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	9.5	mmbtu/hr	GCP/CBF	0.03	LB/H	BACT
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	NORTHSTAR BLUESCOPE STEEL, LLC	09/27/2019	30	MMBTU/H	GCP/CBF	0.3	LB/H	BACT
				$PM_{2.5}$ (filterable only)					
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	09/21/2021	10	MMBtu/hr		0.008	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	0.0075	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	0.0075	LB/MMBTU	BACT
				Greenhouse Gases -Carbon Dioxide					
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/Boiler Efficiency	117	LB/MMBTU	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/Boiler Efficiency	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Boiler Efficiency	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Boiler Efficiency	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP	117	LB/MMBTU	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/Boiler Efficiency	117	LB/MMBTU	BACT
				Sulfuric Acid Mist					
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	13	mmBtu/hour	GCP	0.014	POUNDS/HOUR	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

Table D-4 Addendum: RBLC Results for Natural Gas Heater
UPDATED DATA: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
Opacity									
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	0		GCP/CBF	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	5	%	BACT
AR-0155	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	11/07/2018	53.7	MMBTU/HR	GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0159	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	04/05/2019	0		GCP/CBF	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	0		GCP	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	3	MMBTU/hr each	GCP	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	50.4	MMBTU/hr	GCP	5	%	BACT
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	15	MMBTU/hr each	GCP	5	%	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		GCP	5	%	BACT
*AR-0172	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	09/01/2021	0		Wet Scrubber System with mist eliminator	10	%	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP/LNB	15	%	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0		GCP/LNB	15	%	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	1.5	mmBTU/hr	GCP	10	%	BACT

(a) GCP = good combustion practices, LNB = low-NOx burners, CBF = clean burning fuels, FGR = flue gas recirculation

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
			Carbon Monoxide						
OK-0154	Mooreland Generating Sta	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	1,341	HP	GCP	0.00	g/hp-hr	BACT-PSD
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.01	g/hp-hr	Other Case-by-Case
PA-0278	Moxie Liberty LLC/Asylum Power Pl T	MOXIE ENERGY LLC	10/10/2012			None	0.13	g/hp-hr	Other Case-by-Case
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	1,341	HP	NSPS Compliance	0.21	g/hp-hr	BACT-PSD
NV-0047	Nellis Air Force Base	99 CIVIL ENGINEER SQUADRON OF USAF	2/26/2008	1,350	hP	Turbocharger	0.22	g/hp-hr	Other Case-by-Case
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	0.31	g/hp-hr	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			GCP	0.45	g/hp-hr	BACT-PSD
NV-0050	MGM Mirage	MGM MIRAGE	11/30/2009	2,206	HP	Turbocharger	0.82	g/hp-hr	LAER
SC-0115	GP Clarendon LP	GP CLARENDON LP	2/10/2009	1,400	HP	GCP	0.98	g/hp-hr	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	1,400	HP	None	0.98	g/hp-hr	BACT-PSD
PA-0291	Hickory Run Energy Station	HICKORY RUN ENERGY LLC	4/23/2013	1,135	hP	None	2.31	g/hp-hr	Other Case-by-Case
NV-0049	Harrah's Operating Company, Inc.	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	1,232	HP	Turbocharger	2.49	g/hp-hr	Other Case-by-Case
AL-0301	Nucor Steel Tuscaloosa, Inc.	NUCOR STEEL TUSCALOOSA, INC.	7/22/2014	800	HP	None	2.49	g/hp-hr	BACT-PSD
OK-0128	Mid American Steel Rolling Mill	MID AMERICAN STEEL AND WIRE COMPANY	9/8/2008	1,200	HP	None	2.49	g/hp-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	2.60	g/hp-hr	BACT-PSD
MI-0406	Renaissance Power LLC	LS POWER DEVELOPMENT LLC	11/1/2013	1,000	kW	GCP	2.60	g/hp-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	2,584	HP	NSPS Compliance	2.60	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	2.60	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	2.60	g/hp-hr	BACT-PSD
AK-0066	Endicott Production Facility, Liberty Development Project	BRITISH PETROLEUM EXPLORATION ALASKA (BPXA)	6/15/2009	1,041	HP	GCP	2.60	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP	2.60	g/hp-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	1,250	HP	GCP, Clean Fuel	2.60	g/hp-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	2,000	kW	None	2.60	g/hp-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	2,683	HP	None	2.60	g/hp-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	2,016	HP	None	2.60	g/hp-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	2.60	g/hp-hr	Other Case-by-Case
AK-0082	Point Thomson Production Facility	EXXON MOBIL CORPORATION	1/23/2015	2,695	HP	None	2.60	g/hp-hr	BACT-PSD
LA-0288	Lake Charles Chemical Complex	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	2.61	g/hp-hr	BACT-PSD
LA-0296	Lake Charles Chemical Complex LDPE Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	2.61	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	2.61	g/hp-hr	BACT-PSD

Emergency Generator

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	2.61	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	2.61	g/hp-hr	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	2.61	g/hp-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	2,250	kW	NSPS Compliance	3.50	g/hp-hr	BACT-PSD
FL-0310	Shady Hills Generating Station	SHADY HILLS POWER COMPANY	1/12/2009	2,500	kW	NSPS Compliance	8.50	g/hp-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	2,200	HP	None	3.50	g/kW-hr	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	1,600	kW	GCP	3.50	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	3.50	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	3.50	g/kW-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	1,175	hP	None	3.50	g/kW-hr	BACT-PSD
IA-0095	Tate & Lyle Ingredients Americas, Inc.		9/19/2008	700	kW	None	3.50	g/kW-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	2,922	HP	GCP	3.50	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	3.50	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	3.50	g/kW-hr	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	2,000	kW	GCP, Clean Fuel	3.50	g/kW-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	3.50	g/kW-hr	BACT-PSD
FL-0332	Highlands Biorefinery And Cogeneration Plant	HIGHLANDS ENVIROFUELS (HEF), LLC	9/23/2011	2,682	hP	NSPS Compliance	3.50	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	750	kW	GCP	3.50	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	3.50	g/kW-hr	BACT-PSD
AK-0076	Point Thomson Production Facility	EXXON MOBIL CORPORATION	8/20/2012	1,750	kW	None	3.50	g/kW-hr	BACT-PSD
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	2,000	kW	None	3.50	g/kW-hr	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FLORIDA POWER & LIGHT	3/9/2016	3,300	kW	GCP	3.50	g/kW-hr	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	1,200	HP	GCP	3.50	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	757	HP	NSPS Compliance	3.50	g/kW-hr	BACT-PSD
FL-0346	Lauderdale Plant	FLORIDA POWER & LIGHT	4/22/2014	3,100	kW	GCP	3.50	g/kW-hr	BACT-PSD
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	1,389	HP	GCP	0.85	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide									
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	526.39	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	526.39	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	526.39	g/hp-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	1.55	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	703.07	g/kW-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	1,250	HP	GCP	163.00	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide Equivalents									

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~ Emergency Generator

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	444.05	g/hp-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	2,016	HP	None	543.67	g/hp-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	162.85	lb/MMBtu	BACT-PSD
Sulfuric Acid Mist									
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	5.44E-04	g/kW-hr	BACT-PSD
NY-0101	Cornell Combined Heat & Power Project	CORNELL UNIVERSITY	3/12/2008	1,000	kW	Clean fuels	9.07E-04	g/kW-hr	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			Clean fuels	3.00E-05	lb/MMBtu	BACT-PSD
Nitrogen Oxides									
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.02	g/hp-hr	LAER
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	2.85	g/hp-hr	BACT-PSD
CA-1221	Pacific Bell	PACIFIC BELL	12/5/2011	3,634	HP	NSPS Compliance	3.50	g/hp-hr	Other Case-by-Case
SC-0115	GP CLARENDON LP	GP CLARENDON LP	2/10/2009	1,400	HP	GCP	3.70	g/hp-hr	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	1,400	HP	None	3.70	g/hp-hr	BACT-PSD
CA-1220	San Diego International Airport	SAN DIEGO INTERNATIONAL AIRPORT	10/3/2011	1,881	HP	NSPS Compliance	3.90	g/hp-hr	Other Case-by-Case
PA-0291	Hickory Run Energy Station	HICKORY RUN ENERGY LLC	4/23/2013	1,135	hP	None	3.95	g/hp-hr	Other Case-by-Case
CA-1219	City Of San Diego PUD (Pump Station 1)	CITY OF SAN DIEGO PUD (PUMP STATION 1)	7/9/2012	2,722	HP	NSPS Compliance	4.00	g/hp-hr	Other Case-by-Case
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	4.42	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	4.46	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	4.46	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	4.46	g/hp-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	2,000	kW	None	4.50	g/hp-hr	BACT-PSD
LA-0288	Lake Charles Chemical Complex	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	4.63	g/hp-hr	BACT-PSD
LA-0296	Lake Charles Chemical Complex LDPE Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	4.63	g/hp-hr	BACT-PSD
AK-0066	Endicott Production Facility, Liberty Development Project	BRITISH PETROLEUM EXPLORATION ALASKA (BPXA)	6/15/2009	1,041	HP	GCP	4.70	g/hp-hr	BACT-PSD
WV-0027	Inwood	KNAUF INSULATION INC.	9/15/2017	900	HP	GCP, Clean Fuel	4.77	g/hp-hr	BACT-PSD
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	2,000	kW	GCP	4.78	g/hp-hr	BACT-PSD
MI-0406	Renaissance Power LLC	LS POWER DEVELOPMENT LLC	11/1/2013	1,000	kW	GCP	4.80	g/hp-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	2,584	HP	NSPS Compliance	4.80	g/hp-hr	BACT-PSD
LA-0292	Holbrook Compressor Station	CAMERON INTERSTATE PIPELINE LLC	1/22/2016	1,341	HP	GCP, Clean Fuel	4.80	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	4.80	g/hp-hr	BACT-PSD

Emergency Generator

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	4.80	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP	4.80	g/hp-hr	LAER
MD-0043	Perryman Generating Station	CONSTELLATION POWER SOURCE GENERATION, INC.	7/1/2014	1,300	HP	GCP	4.80	g/hp-hr	LAER
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	2,683	HP	None	4.80	g/hp-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	2,016	HP	None	4.80	g/hp-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	4.80	g/hp-hr	LAER
AK-0082	Point Thomson Production Facility	EXXON MOBIL CORPORATION	1/23/2015	2,695	HP	None	4.80	g/hp-hr	BACT-PSD
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	4.85	g/hp-hr	BACT-PSD
PA-0278	Moxie Liberty LLC/Asylum Power Pl T	MOXIE ENERGY LLC	10/10/2012			None	4.93	g/hp-hr	Other Case-by-Case
DC-0009	Blue Plains Advanced Wastewater Treatment Plant	DISTRICT OF COLUMBIA WATER AND SEWER AUTHORITY	3/15/2012	2,682	HP	None	5.39	g/hp-hr	LAER
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	2,250	kW	NSPS Compliance	5.60	g/hp-hr	BACT-PSD
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	1,341	HP	NSPS Compliance	5.78	g/hp-hr	BACT-PSD
OK-0128	Mid American Steel Rolling Mill	MID AMERICAN STEEL AND WIRE COMPANY	9/8/2008	1,200	HP	None	5.90	g/hp-hr	BACT-PSD
NV-0050	MGM Mirage	MGM MIRAGE	11/30/2009	2,206	HP	Turbocharger	5.94	g/hp-hr	Other Case-by-Case
MD-0037	Medimmune Frederick Campus	MEDIMMUNE, INC.	1/28/2008	2,500	kW	None	6.06	g/hp-hr	LAER
AL-0301	Nucor Steel Tuscaloosa, Inc.	NUCOR STEEL TUSCALOOSA, INC.	7/22/2014	800	HP	None	6.80	g/hp-hr	BACT-PSD
FL-0310	Shady Hills Generating Station	SHADY HILLS POWER COMPANY	1/12/2009	2,500	kW	NSPS Compliance	6.90	g/hp-hr	BACT-PSD
NV-0047	Nellis Air Force Base	99 CIVIL ENGINEER SQUADRON OF USAF	2/26/2008	1,350	hP	Turbocharger	7.58	g/hp-hr	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	1,232	HP	Turbocharger	10.89	g/hp-hr	BACT-PSD
NJ-0073	Trigen	TRIGEN - TRENTON ENERGY CORP	3/8/2008			None	12.00	g/hp-hr	RACT
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	0.67	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	1.33	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	757	HP	NSPS Compliance	4.00	g/kW-hr	BACT-PSD
OK-0154	Mooreland Generating Sta	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	1,341	HP	GCP	4.99	g/kW-hr	BACT-PSD
MI-0394	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER-WARREN	2/29/2012	3,010	kW	GCP, ITR	5.98	g/kW-hr	BACT-PSD
MI-0395	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER--WARREN	7/13/2012	3,010	kW	GCP, ITR	5.98	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	6.00	g/kW-hr	BACT-PSD
IA-0095	Tate & Lyle Ingredients Americas, Inc.		9/19/2008	700	kW	None	6.20	g/kW-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	2,200	HP	None	6.40	g/kW-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	1,175	hP	None	6.40	g/kW-hr	LAER
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	2,922	HP	GCP	6.40	g/kW-hr	BACT-PSD

Emergency Generator

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
AK-0073	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION	12/20/2010	1,500	kW	GCP	6.40	g/kW-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	6.40	g/kW-hr	BACT-PSD
FL-0332	Highlands Biorefinery And Cogeneration Plant	HIGHLANDS ENVIROFUELS (HEF), LLC	9/23/2011	2,682	hP	NSPS Compliance	6.40	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	750	kW	GCP	6.40	g/kW-hr	BACT-PSD
AK-0076	Point Thomson Production Facility	EXXON MOBIL CORPORATION	8/20/2012	1,750	kW	None	6.40	g/kW-hr	BACT-PSD
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	2,000	kW	None	6.40	g/kW-hr	BACT-PSD
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	2,922	HP	NSPS Compliance	6.40	g/kW-hr	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	1,200	HP	GCP	6.40	g/kW-hr	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	1,600	kW	GCP	6.41	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	6.41	g/kW-hr	BACT-PSD
MI-0394	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER-WARREN	2/29/2012	2,280	kW	GCP, ITR	6.93	g/kW-hr	BACT-PSD
MI-0395	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER--WARREN	7/13/2012	2,500	kW	GCP, ITR	7.13	g/kW-hr	BACT-PSD
MI-0418	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER - WARREN	1/14/2015	2,710	kW	GCP, ITR	7.13	g/kW-hr	BACT-PSD
MI-0418	Warren Technical Center	GENERAL MOTORS TECHNICAL CENTER - WARREN	1/14/2015	3,490	kW	GCP, ITR	8.00	g/kW-hr	BACT-PSD
AK-0072	Dutch Harbor Power Plant	CITY OF UNALASKA	7/14/2011	4,400	kW	GCP	9.80	g/kW-hr	BACT-PSD
NH-0015	Concord Steam Corporation	CONCORD STEAM CORPORATION	2/27/2009			None	1.98	lb/MMBtu	LAER
NH-0015	Concord Steam Corporation	CONCORD STEAM CORPORATION	2/27/2009			None	1.98	lb/MMBtu	LAER
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	1,389	HP	GCP	3.20	lb/MMBtu	BACT-PSD
PM10 - filterable									
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.05	g/hp-hr	Other Case-by-Case
NV-0050	MGM Mirage	MGM MIRAGE	11/30/2009	2,206	HP	Turbocharger	0.05	g/hp-hr	Other Case-by-Case
SC-0115	GP Clarendon LP	GP CLARENDON LP	2/10/2009	1,400	HP	GCP	0.06	g/hp-hr	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	1,400	HP	None	0.06	g/hp-hr	BACT-PSD
NV-0047	Nellis Air Force Base	99 CIVIL ENGINEER SQUADRON OF USAF	2/26/2008	1,350	hP	Turbocharger	0.08	g/hp-hr	Other Case-by-Case
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	0.15	g/hp-hr	BACT-PSD
AK-0082	Point Thomson Production Facility	EXXON MOBIL CORPORATION	1/23/2015	2,695	HP	None	0.15	g/hp-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	2,584	HP	GCP	0.15	g/hp-hr	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	1,232	HP	Turbocharger	0.32	g/hp-hr	Other Case-by-Case
IA-0095	Tate & Lyle Ingredients Americas, Inc.		9/19/2008	700	kW	None	0.20	g/kW-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	2,922	HP	GCP	0.20	g/kW-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	1,175	hP	None	0.20	g/kW-hr	BACT-PSD
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	2,000	kW	GCP	0.24	g/kW-hr	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
				PM10 - total					
PA-0278	Moxie Liberty LLC/Asylum Power Pl T	MOXIE ENERGY LLC	10/10/2012			None	0.02	g/hp-hr	Other Case-by-Case
LA-0231	Lake Charles Gasification Facility	LAKE CHARLES COGENERATION, LLC	6/22/2009	1,341	HP	NSPS Compliance	0.02	g/hp-hr	BACT-PSD
AK-0073	International Station Power Plant	CHUGACH ELECTRIC ASSOCIATION	12/20/2010	1,500	kW	Turbo Charging	0.03	g/hp-hr	BACT-PSD
LA-0288	Lake Charles Chemical Complex	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	0.15	g/hp-hr	BACT-PSD
LA-0296	Lake Charles Chemical Complex LDPE Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
MI-0406	Renaissance Power LLC	LS POWER DEVELOPMENT LLC	11/1/2013	1,000	kW	GCP	0.15	g/hp-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	0.15	g/hp-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	1,250	HP	GCP, Clean Fuel	0.15	g/hp-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	2,683	HP	Clean fuels	0.15	g/hp-hr	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	0.15	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP, Clean Fuel	0.17	g/hp-hr	BACT-PSD
MD-0043	Perryman Generating Station	CONSTELLATION POWER SOURCE GENERATION, INC.	7/1/2014	1,300	HP	GCP	0.17	g/hp-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	2,250	kW	NSPS Compliance	0.20	g/hp-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	4,000	HP	None	0.20	g/hp-hr	BACT-PSD
WV-0027	Inwood	KNAUF INSULATION INC.	9/15/2017	900	HP	Clean fuels	0.20	g/hp-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	0.25	g/hp-hr	BACT-PSD
OK-0128	Mid American Steel Rolling Mill	MID AMERICAN STEEL AND WIRE COMPANY	9/8/2008	1,200	HP	None	0.32	g/hp-hr	BACT-PSD
FL-0310	Shady Hills Generating Station	SHADY HILLS POWER COMPANY	1/12/2009	2,500	kW	GCP, Clean Fuel	0.40	g/hp-hr	BACT-PSD
FL-0310	Shady Hills Generating Station	SHADY HILLS POWER COMPANY	1/12/2009	2,500	kW	Clean fuels	0.40	g/hp-hr	BACT-PSD
AR-0140	Big River Steel LLC	BIG RIVER STEEL LLC	9/18/2013	1,500	kW	GCP	0.04	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.07	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	0.10	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.20	g/kW-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	2,200	HP	None	0.20	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	0.20	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	0.20	g/kW-hr	BACT-PSD

Emergency Generator

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	2,922	HP	NSPS Compliance	0.20	g/kW-hr	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	1,200	HP	GCP	0.20	g/kW-hr	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	1,600	kW	GCP	0.40	g/kW-hr	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	2,000	kW	GCP, Clean Fuel	0.06	lb/MMBtu	BACT-PSD
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	0.06	lb/MMBtu	BACT-PSD
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	1,389	HP	GCP	0.10	lb/MMBtu	BACT-PSD
IN-0166	Indiana Gasification, LLC	INDIANA GASIFICATION, LLC	6/27/2012	1,341	HP	Clean fuels	15.00	ppm Sulfur	BACT-PSD
PM2.5 - filterable									
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.05	g/hp-hr	Other Case-by-Case
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	0.15	g/hp-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	2,016	HP	None	0.15	g/hp-hr	BACT-PSD
AK-0082	Point Thomson Production Facility	EXXON MOBIL CORPORATION	1/23/2015	2,695	HP	None	0.15	g/hp-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	2,584	HP	GCP	0.15	g/hp-hr	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	1,200	HP	GCP	0.20	g/kW-hr	BACT-PSD
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	2,000	kW	GCP	0.24	g/kW-hr	BACT-PSD
AK-0072	Dutch Harbor Power Plant	CITY OF UNALASKA	7/14/2011	4,400	kW	Positive Crankcase Ventilation	0.50	g/kW-hr	BACT-PSD
PM2.5 - total									
PA-0278	Moxie Liberty LLC/Asylum Power Pl T	MOXIE ENERGY LLC	10/10/2012			None	0.02	g/hp-hr	Other Case-by-Case
LA-0288	Lake Charles Chemical Complex	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	0.15	g/hp-hr	BACT-PSD
LA-0296	Lake Charles Chemical Complex LDPE Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	0.15	g/hp-hr	BACT-PSD
OK-0154	Mooreland Generating Sta	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	1,341	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
MI-0406	Renaissance Power LLC	LS POWER DEVELOPMENT LLC	11/1/2013	1,000	kW	GCP	0.15	g/hp-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	0.15	g/hp-hr	BACT-PSD
LA-0292	Holbrook Compressor Station	CAMERON INTERSTATE PIPELINE LLC	1/22/2016	1,341	HP	GCP, Clean Fuel	0.15	g/hp-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	1,250	HP	GCP, Clean Fuel	0.15	g/hp-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	2,000	kW	Clean fuels	0.15	g/hp-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	2,683	HP	Clean fuels	0.15	g/hp-hr	BACT-PSD

Table D-5 - RBLC Results for Emergency Generator **~~Emergency Fire Pump~~**

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	750	kW	None	0.15	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP, Clean Fuel	0.17	g/hp-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	4,000	HP	None	0.20	g/hp-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	0.25	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	68.04	g/hp-hr	BACT-PSD
AR-0140	Big River Steel LLC	BIG RIVER STEEL LLC	9/18/2013	1,500	kW	GCP	0.04	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.07	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	0.10	g/kW-hr	BACT-PSD
AK-0081	Point Thomson Production Facility	EXXONMOBIL CORPORATION	6/12/2013	610	HP	GCP	0.15	g/kW-hr	Other Case-by-Case
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.20	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	0.20	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	0.20	g/kW-hr	BACT-PSD
AK-0076	Point Thomson Production Facility	EXXON MOBIL CORPORATION	8/20/2012	1,750	kW	None	0.20	g/kW-hr	BACT-PSD
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	2,922	HP	NSPS Compliance	0.20	g/kW-hr	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	1,600	kW	GCP	0.40	g/kW-hr	BACT-PSD
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	0.06	lb/MMBtu	BACT-PSD
IN-0166	Indiana Gasification, LLC	INDIANA GASIFICATION, LLC	6/27/2012	1,341	HP	Clean fuels	15.00	ppm Sulfur	BACT-PSD
PM - filterable									
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			Clean fuels	0.03	g/hp-hr	BACT-PSD
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.05	g/hp-hr	Other Case-by-Case
MI-0402	Sumpter Power Plant	WOLVERINE POWER SUPPLY COOPERATIVE INC.	11/17/2011	732	HP	GCP	0.05	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
MI-0406	Renaissance Power LLC	LS POWER DEVELOPMENT LLC	11/1/2013	1,000	kW	GCP	0.15	g/hp-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	0.15	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	0.15	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	0.15	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP, Clean Fuel	0.15	g/hp-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	4,000	HP	None	0.15	g/hp-hr	BACT-PSD
AL-0301	Nucor Steel Tuscaloosa, Inc.	NUCOR STEEL TUSCALOOSA, INC.	7/22/2014	800	HP	None	0.32	g/hp-hr	BACT-PSD
AR-0140	Big River Steel LLC	BIG RIVER STEEL LLC	9/18/2013	1,500	kW	GCP	0.02	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	0.10	g/kW-hr	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IA-0095	Tate & Lyle Ingredients Americas, Inc.		9/19/2008	700	kW	None	0.20	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	750	kW	GCP	0.20	g/kW-hr	BACT-PSD
MI-0421	Grayling Particleboard	ARAUCO NORTH AMERICA	8/26/2016	1,600	kW	GCP	0.20	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.20	g/kW-hr	BACT-PSD
MI-0425	Grayling Particleboard	ARAUCO NORTH AMERICA	5/9/2017	1,500	kW	GCP	0.20	g/kW-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	0.20	g/kW-hr	BACT-PSD
IN-0166	Indiana Gasification, LLC	INDIANA GASIFICATION, LLC	6/27/2012	1,341	HP	Clean fuels	15.00	ppm Sulfur	BACT-PSD
PM - total									
SC-0115	GP Clarendon LP	GP CLARENDON LP	2/10/2009	1,400	HP	GCP	0.08	g/hp-hr	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	1,400	HP	None	0.08	g/hp-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	2,000	kW	Clean fuels	0.15	g/hp-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	2,683	HP	Clean fuels	0.15	g/hp-hr	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	0.15	g/hp-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	0.20	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	0.20	g/kW-hr	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	2,000	kW	GCP, Clean Fuel	0.20	g/kW-hr	BACT-PSD
FL-0332	Highlands Biorefinery And Cogeneration Plant	HIGHLANDS ENVIROFUELS (HEF), LLC	9/23/2011	2,682	hP	NSPS Compliance	0.20	g/kW-hr	BACT-PSD
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	2,000	kW	None	0.20	g/kW-hr	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FLORIDA POWER & LIGHT	3/9/2016	3,300	kW	Clean fuels	0.20	g/kW-hr	BACT-PSD
FL-0346	Lauderdale Plant	FLORIDA POWER & LIGHT	4/22/2014	3,100	kW	GCP	0.20	g/kW-hr	BACT-PSD
Volatile Organic Compounds									
PA-0278	Moxie Liberty LLC/Asylum Power Pl T	MOXIE ENERGY LLC	10/10/2012			None	0.01	g/hp-hr	Other Case-by-Case
SC-0115	GP Clarendon LP	GP CLARENDON LP	2/10/2009	1,400	HP	GCP	0.10	g/hp-hr	BACT-PSD
SC-0114	GP Allendale LP	GP ALLENDALE LP	11/25/2008	1,400	HP	None	0.10	g/hp-hr	BACT-PSD
NV-0050	MGM Mirage	MGM MIRAGE	11/30/2009	2,206	HP	Turbocharger	0.14	g/hp-hr	Other Case-by-Case
LA-0296	Lake Charles Chemical Complex LDPE Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	NSPS Compliance	0.14	g/hp-hr	BACT-PSD
LA-0288	Lake Charles Chemical Complex	SASOL CHEMICALS (USA) LLC	5/23/2014	2,682	HP	GCP	0.14	g/hp-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	670	hP	None	0.15	g/hp-hr	BACT-PSD
NV-0047	Nellis Air Force Base	99 CIVIL ENGINEER SQUADRON OF USAF	2/26/2008	1,350	hP	Turbocharger	0.20	g/hp-hr	Other Case-by-Case
TX-0728	Peony Chemical Manufacturing Facility	BASF	4/1/2015	1,500	HP	NSPS Compliance	0.21	g/hp-hr	Other Case-by-Case
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	2,012	HP	GCP	0.23	g/hp-hr	BACT-PSD

Emergency Generator

Table D-5 - RBLC Results for ~~Emergency Fire Pump~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	2,016	HP	None	0.28	g/hp-hr	BACT-PSD
PA-0291	Hickory Run Energy Station	HICKORY RUN ENERGY LLC	4/23/2013	1,135	hP	None	0.28	g/hp-hr	Other Case-by-Case
LA-0292	Holbrook Compressor Station	CAMERON INTERSTATE PIPELINE LLC	1/22/2016	1,341	HP	GCP	0.28	g/hp-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	2,922	hP	GCP	0.29	g/hp-hr	BACT-PSD
OK-0128	Mid American Steel Rolling Mill	MID AMERICAN STEEL AND WIRE COMPANY	9/8/2008	1,200	HP	None	0.29	g/hp-hr	BACT-PSD
VA-0327	Perdue Grain And Oilseed, LLC	PERDUE AGRIBUSINESS, LLC	7/12/2017	760	hP	None	0.29	g/hp-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.31	g/hp-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	4,690	HP	GCP	0.31	g/hp-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	3,600	HP	GCP	0.31	g/hp-hr	BACT-PSD
NV-0049	Harrah's Operating Company, Inc.	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	1,232	HP	Turbocharger	0.32	g/hp-hr	Other Case-by-Case
AK-0082	Point Thomson Production Facility	EXXON MOBIL CORPORATION	1/23/2015	2,695	HP	None	0.32	g/hp-hr	BACT-PSD
OK-0154	Mooreland Generating Sta	WESTERN FARMERS ELECTRIC COOPERATIVE	7/2/2013	1,341	HP	GCP	0.32	g/hp-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	2,200	HP	GCP	0.32	g/hp-hr	BACT-PSD
IN-0263	Midwest Fertilizer Company LLC	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	3,600	HP	GCP	0.35	g/hp-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	1,006	HP	GCP	0.47	g/hp-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	2,250	kW	NSPS Compliance	0.79	g/hp-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	1,250	HP	GCP, Clean Fuel	1.00	g/hp-hr	BACT-PSD
OK-0175	Wildhorse Terminal	WILDHORSE TERMINAL LLC	6/29/2017	500	hP	GCP	3.00	g/hp-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	2,584	HP	GCP	4.80	g/hp-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	1,550	HP	GCP, Clean Fuel	4.80	g/hp-hr	LAER
IA-0095	Tate & Lyle Ingredients Americas, Inc.		9/19/2008	700	kW	None	0.20	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	2,000	kW	GCP	0.40	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	3,755	HP	NSPS Compliance	0.40	g/kW-hr	BACT-PSD
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	CF INDUSTRIES NITROGEN, LLC	7/12/2013			GCP	4.00	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	757	HP	NSPS Compliance	4.00	g/kW-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	2,922	HP	GCP	6.40	g/kW-hr	BACT-PSD
SC-0159	US10 Facility	MICHELIN NORTH AMERICA, INC.	7/9/2012	1,000	kW	NSPS Compliance	6.40	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	750	kW	GCP	6.40	g/kW-hr	BACT-PSD
LA-0272	Ammonia Production Facility	DYNO NOBEL LOUISIANA AMMONIA, LLC	3/27/2013	1,200	HP	GCP	6.40	g/kW-hr	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			GCP	0.03	lb/MMBtu	LAER

Table D-5 Addendum: RBLC Results for Emergency Generator
Updated Data: November 2018 to October 2021

From December 2021 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
			Nitrogen Oxides						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	2	G/KW-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	920	HP	GCP	4.77	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	700	HP	GCP	4.77	G/HP-HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	1500	HP	GCP	6.4	G/KW-H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	14.96	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	3	G/HP-HR	BACT
			Carbon Monoxide						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	4	G/KW-HR	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	1500	kW		3.5	G/KW-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	920	HP	GCP	2.61	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	700	HP	GCP	2.61	G/HP-HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	1500	HP	GCP	3.5	G/KW-H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	4474.2	KW	GCP	3.5	G/KW-H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	7.7	LB/H	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP/engine design	0.5	G	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP/engine design	0.5	G	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP/engine design	387	GRAM	BACT
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	08/08/2020	0		GCP/engine design	100	HR/YR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	2.6	G/HP-H	BACT
			Volatile Organic Compounds						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	1	G/KW-HR	BACT
LA-0366	HOLDEN WOOD PRODUCTS MILL	WEYERHAEUSER NR COMPANY	02/03/2021	0		GCP	804.6	HP	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	14.96	LB/H	BACT
OK-0181	WILDHORSE TERMINAL	KEYERA ENERGY INC	09/11/2019	0		GCP	3	GM/HP-HR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.11	G/HP-HR	BACT
			PM_{10} (total)						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	0.2	G/KW-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	920	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	700	HP	GCP	0.15	G/HP-HR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	700	HP	GCP	0.15	G/HP-HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	1500	HP	GCP/CBF	0.69	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	4474.2	KW	GCP/CBF	1	LB/H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	0.44	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
			$PM_{2.5}$ (total)						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	0.2	G/KW-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	920	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	700	HP	GCP	0.15	G/HP-HR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	700	HP	GCP	0.15	G/HP-HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	1500	HP	CBF	0.69	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	4474.2	KW	CBF	1	LB/H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	0.44	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
			Greenhouse Gases - CO2 Equivalents						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	163	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	1500	kW		225	TONS/YEAR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	1500	HP	GCP/energy efficiency measures.	406	T/YR	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	4474.2	KW	GCP/CBF/energy efficiency measures.	590	T/YR	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	1341	HP	GCP	80	T/YR	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	10	TONS	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	10	TONS	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	106	T/YR	BACT
			Sulfuric Acid Mist						
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.0001	LB/MMBTU	BACT
			Opacity						
AR-0171	NUCOR STEEL ARKANSAS	NUCOR CORPORATION	02/14/2019	1073	bhp	GCP	20	%	BACT

(a) GCP = good combustion practices, CBF = clean burning fuels

Emergency Fire Pump

Table D-6 - RBLC Results for ~~Emergency Generator~~

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
Carbon Monoxide									
CA-1192	Avenal Energy Project	AVENAL POWER CENTER LLC	6/21/2011	288	HP	Turbocharger, aftercooler	0.45	g/HP-hr	BACT-PSD
NY-0103	Cricket Valley Energy Center	CRICKET VALLEY ENERGY CENTER LLC	2/3/2016	460	HP	GCP	0.53	g/HP-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	444	HP	GCP	0.66	g/HP-hr	BACT-PSD
IN-0234	Grain Processing Corporation	GRAIN PROCESSING CORPORATION	12/8/2015	425	HP	GCP	2.01	g/HP-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	300	HP	NSPS	2.57	g/HP-hr	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	STONEGATE POWER, LLC	7/19/2016	327	HP	Clean Fuels	2.59	g/HP-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	267	HP	None	2.60	g/HP-hr	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	300	HP	None	2.60	g/HP-hr	BACT-PSD
MD-0041	CPV St. Charles	CPV MARYLAND, LLC	4/23/2014	300	HP	GCP, Clean Fuels	2.60	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	2.60	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP, NSPS	2.60	g/HP-hr	BACT-PSD
LA-0301	Lake Charles Chemical Complex Ethylene 2 Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	500	HP	GCP, NSPS	2.60	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.60	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.60	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.60	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.60	g/HP-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	350	HP	GCP, Clean Fuels	2.60	g/HP-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	300	HP	GCP	2.60	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	2.60	g/HP-hr	BACT-PSD
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/7/2014	250	HP	None	2.60	g/HP-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	282	HP	GCP, NSPS	2.60	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	2.60	g/HP-hr	BACT-PSD
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	600	HP	None	2.60	g/HP-hr	BACT-PSD

Emergency Fire Pump

Table D-6 - RBLC Results for ~~Emergency Generator~~

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
MI-0410	Thetford Generating Station	CONSUMERS ENERGY COMPANY	7/25/2013	315	HP	GCP, Clean Fuels	2.60	g/HP-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	251	HP	None	2.60	g/HP-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	350	HP	GCP	3.00	g/HP-hr	BACT-PSD
LA-0224	Arsenal Hill Power Plant	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	310	HP	GCP, Clean Fuels	3.03	g/HP-hr	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	3.70	g/HP-hr	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	3.70	g/HP-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	3.50	g/kW-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	193	HP	None	3.50	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	3.50	g/kW-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	300	HP	GCP, Clean Fuels	3.50	g/kW-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	1500	KW	GCP, Clean Fuels	3.50	g/kW-hr	BACT-PSD
FL-0346	Lauderdale Plant	FLORIDA POWER & LIGHT	4/22/2014	300	HP	GCP	3.50	g/kW-hr	BACT-PSD
FL-0354	Lauderdale Plant	FLORIDA POWER & LIGHT	8/25/2015	300	HP	Clean Fuels	3.50	g/kW-hr	BACT-PSD
MD-0045	Mattawoman Energy Center	MATTAWOMAN ENERGY, LLC	11/13/2015	305	HP	GCP, Clean Fuels	3.50	g/kW-hr	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FLORIDA POWER & LIGHT	3/9/2016	422	HP	GCP	3.50	g/kW-hr	BACT-PSD
FL-0324	Palm Beach Renewable Energy Park	SOLID WASTE AUTHORITY OF PALM BEACH COUNTY	12/23/2010	250	kW	GCP, Clean Fuels	3.50	g/kW-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	182	HP	None	3.50	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	500	HP	NSPS	3.50	g/kW-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	135	KW	None	3.50	g/kW-hr	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	40	KW	GCP, Clean Fuels	5.00	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	29	HP	GCP	5.50	g/kW-hr	BACT-PSD
TX-0799	Beaumont Terminal	PHILLIPS 66 PIPELINE LLC	6/8/2016			GCP	0.01	lb/HP-hr	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/10/2016	2.6	MMBtu/hr	Clean Fuels	0.42	lb/MMBtu	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			GCP	0.75	lb/MMBtu	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	0.95	lb/MMBtu	BACT-PSD
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	420	HP	GCP, Clean Fuels	0.95	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide									
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	527.40	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	527.40	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	527.40	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	527.40	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	527.40	g/HP-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	1.55	g/kW-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	350	HP	GCP	163.00	lb/MMBtu	BACT-PSD
Greenhouse Gases - Carbon Dioxide Equivalents									
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	251	HP	None	558.41	g/HP-hr	BACT-PSD
TX-0612	Thomas C. Ferguson Power Plant	LOWER COLORADO RIVER AUTHORITY	11/10/2011	617	HP	GCP	5,166.54	g/HP-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2.7	MMBtu/hr	None	162.85	lb/MMBtu	BACT-PSD
Sulfuric Acid Mist									
MD-0045	Mattawoman Energy Center	MATTAWOMAN ENERGY, LLC	11/13/2015	305	HP	GCP, Clean Fuels	7.00E-03	g/HP-hr	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			Clean Fuels	3.00E-05	lb/MMBtu	BACT-PSD
NY-0103	Cricket Valley Energy Center	CRICKET VALLEY ENERGY CENTER LLC	2/3/2016	460	HP	Clean Fuels	1.00E-04	lb/MMBtu	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2.7	MMBtu/hr	None	1.11E-04	lb/MMBtu	BACT-PSD
FL-0354	Lauderdale Plant	FLORIDA POWER & LIGHT	8/25/2015	300	HP	Clean Fuels	15.00	ppm Sulfur	BACT-PSD
Nitrogen Dioxide									
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	380	HP	GCP	2.20	g/HP-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	300	HP	NSPS	2.57	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.83	g/HP-hr	BACT-PSD

Table D-6 - RBLC Results for ~~Emergency Generator~~

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.83	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.83	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	2.83	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	2.85	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	2.86	g/HP-hr	BACT-PSD
LA-0301	Lake Charles Chemical Complex Ethylene 2 Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	500	HP	GCP, NSPS	2.91	g/HP-hr	BACT-PSD
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	600	HP	None	3.00	g/HP-hr	BACT-PSD
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	288	HP	NSPS	3.00	g/HP-hr	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	300	HP	None	3.00	g/HP-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	444	HP	None	3.00	g/HP-hr	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	3.00	g/HP-hr	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	3.00	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP, NSPS	3.00	g/HP-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	251	HP	None	3.00	g/HP-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	282	HP	GCP, NSPS	3.00	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	3.00	g/HP-hr	BACT-PSD
MI-0410	Thetford Generating Station	CONSUMERS ENERGY COMPANY	7/25/2013	315	HP	GCP, Clean Fuels	3.00	g/HP-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	420	HP	None	3.00	g/HP-hr	BACT-PSD
CA-1192	Avenal Energy Project	AVENAL POWER CENTER LLC	6/21/2011	288	HP	Turbocharger, aftercooler	3.40	g/HP-hr	BACT-PSD
NV-0047	Nellis Air Force Base	99 CIVIL ENGINEER SQUADRON OF USAF	2/26/2008	500	HP	GCP, NSPS	3.88	g/HP-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	267	HP	None	7.80	g/HP-hr	BACT-PSD

Emergency Fire Pump

From December 2018 Application

Table D-6 - RBLC Results for ~~Emergency Generator~~

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	300	HP	GCP, ITR, Turbocharger, aftercooler	7.80	g/HP-hr	BACT-PSD
IN-0234	Grain Processing Corporation	GRAIN PROCESSING CORPORATION	12/8/2015	425	HP	GCP	9.50	g/HP-hr	BACT-PSD
LA-0224	Arsenal Hill Power Plant	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	310	HP	GCP, Clean Fuels	14.06	g/HP-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	3.50	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	3.75	g/kW-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	135	KW	None	3.80	g/kW-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	193	HP	None	4.00	g/kW-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	300	HP	GCP, Clean Fuels	4.00	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	235	KW	GCP, NSPS	4.00	g/kW-hr	BACT-PSD
FL-0354	Lauderdale Plant	FLORIDA POWER & LIGHT	8/25/2015	300	HP	Clean Fuels	4.00	g/kW-hr	BACT-PSD
FL-0324	Palm Beach Renewable Energy Park	SOLID WASTE AUTHORITY OF PALM BEACH COUNTY	12/23/2010	250	kW	GCP, Clean Fuels	4.00	g/kW-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	182	HP	None	4.00	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	500	HP	NSPS	4.00	g/kW-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	1500	KW	GCP, Clean Fuels	6.40	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	29	HP	GCP	7.50	g/kW-hr	BACT-PSD
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	4.41	lb/MMBtu	BACT-PSD
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	420	HP	GCP, Clean Fuels	4.41	lb/MMBtu	BACT-PSD
PM10 - Filerable									
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	300	HP	None	0.15	g/HP-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	444	HP	None	0.15	g/HP-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	282	HP	GCP, NSPS	0.15	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	0.15	g/HP-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	300	HP	GCP	0.40	g/HP-hr	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
LA-0224	Arsenal Hill Power Plant	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	310	HP	GCP, Clean Fuels	0.99	g/HP-hr	BACT-PSD
LA-0251	Flopam Inc. Facility	FLOPAM INC.	4/26/2011	193	HP	None	0.20	g/kW-hr	BACT-PSD
PM10 - Total									
NJ-0085	Middlesex Energy Center, LLC	STONEGATE POWER, LLC	7/19/2016	327	HP	Clean Fuels	0.15	g/HP-hr	BACT-PSD
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	288	HP	NSPS	0.15	g/HP-hr	BACT-PSD
MD-0041	CPV St. Charles	CPV MARYLAND, LLC	4/23/2014	300	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	0.15	g/HP-hr	BACT-PSD
VA-0319	Gateway Cogeneration 1, LLC - Smart Water Project	GATEWAY GREEN ENERGY	8/27/2012	1.86	MMBtu/hr	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
LA-0301	Lake Charles Chemical Complex Ethylene 2 Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	500	HP	GCP, NSPS	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	350	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	0.15	g/HP-hr	BACT-PSD
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/7/2014	250	HP	Clean Fuels	0.15	g/HP-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2.7	MMBtu/hr	None	0.15	g/HP-hr	BACT-PSD
KS-0029	The Empire District Electric Company	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	750	KW	Clean Fuels	0.15	g/HP-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	300	HP	NSPS	0.15	g/HP-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	420	HP	None	0.15	g/HP-hr	BACT-PSD
IN-0234	Grain Processing Corporation	GRAIN PROCESSING CORPORATION	12/8/2015	425	HP	GCP	0.16	g/HP-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	350	HP	GCP, Clean Fuels	0.17	g/HP-hr	BACT-PSD

Emergency Fire Pump

Table D-6 - RBLC Results for ~~Emergency Generator~~

From December 2018 Application

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	380	HP	GCP	0.18	g/HP-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	300	HP	GCP, Clean Fuels	0.18	g/HP-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	1500	KW	GCP, Clean Fuels	0.18	g/HP-hr	BACT-PSD
MD-0045	Mattawoman Energy Center	MATTAWOMAN ENERGY, LLC	11/13/2015	305	HP	GCP, Clean Fuels	0.18	g/HP-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	267	HP	None	0.40	g/HP-hr	BACT-PSD
MI-0410	Thetford Generating Station	CONSUMERS ENERGY COMPANY	7/25/2013	315	HP	GCP, Clean Fuels	0.86	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP	0.99	g/HP-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	0.10	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	0.20	g/kW-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	182	HP	Clean Fuels	0.20	g/kW-hr	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/10/2016	2.6	MMBtu/hr	Clean Fuels	0.04	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	0.09	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	0.09	lb/MMBtu	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	40	KW	GCP, Clean Fuels	0.31	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	0.31	lb/MMBtu	BACT-PSD
LA-0204	Plaquemine PVC Plant	SHINTECH LOUISIANA LLC	2/27/2009	420	HP	GCP, Clean Fuels	0.31	lb/MMBtu	BACT-PSD
PM2.5 - Total									
NJ-0085	Middlesex Energy Center, LLC	STONEGATE POWER, LLC	7/19/2016	327	HP	Clean Fuels	0.15	g/HP-hr	BACT-PSD
LA-0309	Benteler Steel Tube Facility	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	6/4/2015	288	HP	NSPS	0.15	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	0.15	g/HP-hr	BACT-PSD
VA-0319	Gateway Cogeneration 1, LLC - Smart Water Project	GATEWAY GREEN ENERGY	8/27/2012	1.86	MMBtu/hr	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
LA-0301	Lake Charles Chemical Complex Ethylene 2 Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	500	HP	GCP, NSPS	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	350	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	0.15	g/HP-hr	BACT-PSD
MA-0039	Salem Harbor Station Redevelopment	FOOTPRINT POWER SALEM HARBOR DEVELOPMENT LP	1/30/2014	2.7	MMBtu/hr	None	0.15	g/HP-hr	BACT-PSD
KS-0029	The Empire District Electric Company	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	750	KW	Clean Fuels	0.15	g/HP-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	420	HP	None	0.15	g/HP-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	350	HP	GCP, Clean Fuels	0.17	g/HP-hr	BACT-PSD
MD-0045	Mattawoman Energy Center	MATTAWOMAN ENERGY, LLC	11/13/2015	305	HP	GCP, Clean Fuels	0.18	g/HP-hr	BACT-PSD
MI-0410	Thetford Generating Station	CONSUMERS ENERGY COMPANY	7/25/2013	315	HP	GCP, Clean Fuels	0.86	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP	0.99	g/HP-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	0.10	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	0.20	g/kW-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	182	HP	Clean Fuels	0.20	g/kW-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	135	KW	None	0.20	g/kW-hr	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/10/2016	2.6	MMBtu/hr	Clean Fuels	0.04	lb/MMBtu	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	0.09	lb/MMBtu	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	0.09	lb/MMBtu	BACT-PSD
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	0.31	lb/MMBtu	BACT-PSD
PM2.5 - filterable									
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	282	HP	GCP, NSPS	0.14	g/HP-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	251	HP	None	0.15	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	0.15	g/HP-hr	BACT-PSD

Table D-6 - RBLC Results for ~~Emergency Generator~~ Emergency Fire Pump

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
LA-0308	Morgan City Power Plant	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	9/26/2013	380	HP	GCP	0.18	g/HP-hr	BACT-PSD
PM - filterable									
NY-0103	Cricket Valley Energy Center	CRICKET VALLEY ENERGY CENTER LLC	2/3/2016	460	HP	GCP	0.09	g/HP-hr	BACT-PSD
NJ-0085	Middlesex Energy Center, LLC	STONEGATE POWER, LLC	7/19/2016	327	HP	Clean Fuels	0.15	g/HP-hr	BACT-PSD
MD-0044	Cove Point LNG Terminal	DOMINION COVE POINT LNG, LP	6/9/2014	350	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
MD-0040	CPV St Charles	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	11/12/2008	300	HP	None	0.15	g/HP-hr	BACT-PSD
MD-0041	CPV St. Charles	CPV MARYLAND, LLC	4/23/2014	300	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	0.15	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP, NSPS	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.15	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	0.15	g/HP-hr	BACT-PSD
NJ-0081	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/7/2014	250	HP	Clean Fuels	0.15	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	0.15	g/HP-hr	BACT-PSD
MI-0410	Thetford Generating Station	CONSUMERS ENERGY COMPANY	7/25/2013	315	HP	GCP, Clean Fuels	0.15	g/HP-hr	BACT-PSD
MI-0400	Wolverine Power	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	6/29/2011	420	HP	None	0.15	g/HP-hr	BACT-PSD
IN-0234	Grain Processing Corporation	GRAIN PROCESSING CORPORATION	12/8/2015	425	HP	GCP	0.16	g/HP-hr	BACT-PSD
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	0.22	g/HP-hr	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	0.22	g/HP-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	0.10	g/kW-hr	BACT-PSD

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	300	HP	GCP, Clean Fuels	0.20	g/kW-hr	BACT-PSD
MD-0046	Keys Energy Center	KEYS ENERGY CENTER, LLC	10/31/2014	1500	KW	GCP, Clean Fuels	0.20	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	235	KW	GCP, NSPS	0.20	g/kW-hr	BACT-PSD
MD-0045	Mattawoman Energy Center	MATTAWOMAN ENERGY, LLC	11/13/2015	305	HP	GCP, Clean Fuels	0.20	g/kW-hr	BACT-PSD
NJ-0084	PSEG Fossil LLC Sewaren Generating Station	PSEG FOSSIL LLC	3/10/2016	2.6	MMBtu/hr	Clean Fuels	0.04	lb/MMBtu	BACT-PSD
NY-0104	CPV Valley Energy Center	CPV VALLEY LLC	8/1/2013			Clean Fuels	0.04	lb/MMBtu	BACT-PSD
PM - total									
FL-0322	Sweet Sorghum-To-Ethanol Advanced Biorefinery	SOUTHEAST RENEWABLE FUELS (SRF), LLC	12/23/2010	600	HP	None	0.15	g/HP-hr	BACT-PSD
KS-0029	The Empire District Electric Company	THE EMPIRE DISTRICT ELECTRIC COMPANY	7/14/2015	750	KW	Clean Fuels	0.15	g/HP-hr	BACT-PSD
FL-0346	Lauderdale Plant	FLORIDA POWER & LIGHT	4/22/2014	300	HP	GCP	0.20	g/HP-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	0.20	g/kW-hr	BACT-PSD
FL-0354	Lauderdale Plant	FLORIDA POWER & LIGHT	8/25/2015	300	HP	Clean Fuels	0.20	g/kW-hr	BACT-PSD
FL-0356	Okeechobee Clean Energy Center	FLORIDA POWER & LIGHT	3/9/2016	422	HP	Clean Fuels	0.20	g/kW-hr	BACT-PSD
FL-0324	Palm Beach Renewable Energy Park	SOLID WASTE AUTHORITY OF PALM BEACH COUNTY	12/23/2010	250	kW	GCP, Clean Fuels	0.20	g/kW-hr	BACT-PSD
CA-1212	Palmdale Hybrid Power Project	CITY OF PALMDALE	10/18/2011	182	HP	Clean Fuels	0.20	g/kW-hr	BACT-PSD
CA-1191	Victorville 2 Hybrid Power Project	CITY OF VICTORVILLE	3/11/2010	135	KW	None	0.20	g/kW-hr	BACT-PSD
MI-0389	Karn Weadock Generating Complex	CONSUMERS ENERGY	12/29/2009	40	KW	GCP, Clean Fuels	0.40	g/kW-hr	BACT-PSD
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	0.31	lb/MMBtu	BACT-PSD
Volatile Organic Compounds									
MI-0412	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/4/2013	165	HP	GCP	2.75E-03	g/HP-hr	BACT-PSD
IN-0234	Grain Processing Corporation	GRAIN PROCESSING CORPORATION	12/8/2015	425	HP	GCP	0.05	g/HP-hr	BACT-PSD
LA-0301	Lake Charles Chemical Complex Ethylene 2 Unit	SASOL CHEMICALS (USA) LLC	5/23/2014	500	HP	GCP, NSPS	0.09	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.14	g/HP-hr	BACT-PSD
IN-0173	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.14	g/HP-hr	BACT-PSD
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.14	g/HP-hr	BACT-PSD

Table D-6 - RBLC Results for ~~Emergency Generator~~ Emergency Fire Pump

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls	EmissionLimit	Units	Type
IN-0180	Midwest Fertilizer Corporation	MIDWEST FERTILIZER CORPORATION	6/4/2014	500	HP	GCP	0.14	g/HP-hr	BACT-PSD
IN-0179	Ohio Valley Resources, LLC	OHIO VALLEY RESOURCES, LLC	9/25/2013	481	HP	GCP	0.14	g/HP-hr	BACT-PSD
PR-0009	Energy Answers Arecibo Puerto Rico Renewable Energy Project	ENERGY ANSWERS ARECIBO, LLC	4/10/2014	335	HP	None	0.15	g/HP-hr	BACT-PSD
IN-0158	St. Joseph Energy Center, LLC	ST. JOSEPH ENERGY CENTER, LLC	12/3/2012	371	HP	GCP	0.20	g/HP-hr	BACT-PSD
WV-0025	Moundsville Combined Cycle Power Plant	MOUNDSVILLE POWER, LLC	11/21/2014	251	HP	None	0.31	g/HP-hr	BACT-PSD
OH-0352	Oregon Clean Energy Center	ARCADIS, US, INC.	6/18/2013	300	HP	NSPS	0.38	g/HP-hr	BACT-PSD
LA-0254	Ninemile Point Electric Generating Plant	ENTERGY LOUISIANA LLC	8/16/2011	350	HP	GCP, Clean Fuels	1.00	g/HP-hr	BACT-PSD
MI-0423	Indeck Niles, LLC	INDECK NILES, LLC	1/4/2017	260	HP	GCP	1.12	g/HP-hr	BACT-PSD
OK-0129	Chouteau Power Plant	ASSOCIATED ELECTRIC COOPERATIVE INC	1/23/2009	267	HP	GCP	1.12	g/HP-hr	BACT-PSD
LA-0224	Arsenal Hill Power Plant	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	3/20/2008	310	HP	GCP, Clean Fuels	1.13	g/HP-hr	BACT-PSD
MI-0424	Holland Board Of Public Works - East 5th Street	HOLLAND BOARD OF PUBLIC WORKS	12/5/2016	165	HP	GCP	1.29	g/HP-hr	BACT-PSD
OK-0175	Wildhorse Terminal	WILDHORSE TERMINAL LLC	6/29/2017	500	HP	GCP, NSPS	3.00	g/HP-hr	BACT-PSD
LA-0313	St. Charles Power Station	ENTERGY LOUISIANA, LLC	8/31/2016	282	HP	GCP	3.01	g/HP-hr	BACT-PSD
OH-0317	Ohio River Clean Fuels, LLC	OHIO RIVER CLEAN FUELS, LLC	11/20/2008	300	HP	GCP	7.80	g/HP-hr	BACT-PSD
OK-0164	Midwest City Air Depot	TINKER AIR FORCE BASE LOGISTICS CENTER	1/8/2015	300	HP	GCP	0.15	g/kW-hr	BACT-PSD
IA-0105	Iowa Fertilizer Company	IOWA FERTILIZER COMPANY	10/26/2012	235	kW	GCP	0.25	g/kW-hr	BACT-PSD
IL-0114	Cronus Chemicals, LLC	CRONUS CHEMICALS, LLC	9/5/2014	373	HP	GCP, NSPS	0.40	g/kW-hr	BACT-PSD
ID-0018	Langley Gulch Power Plant	IDAHO POWER COMPANY	6/25/2010	235	KW	GCP, NSPS	4.00	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	500	HP	GCP, NSPS	4.00	g/kW-hr	BACT-PSD
SC-0159	US10 Facility	MICHELIN NORTH AMERICA, INC.	7/9/2012	211	KW	NSPS	4.00	g/kW-hr	BACT-PSD
SC-0113	Pyramax Ceramics, LLC	PYRAMAX CERAMICS, LLC	2/8/2012	29	HP	GCP	7.50	g/kW-hr	BACT-PSD
TX-0799	Beaumont Terminal	PHILLIPS 66 PIPELINE LLC	6/8/2016			GCP	2.50E-03	lb/HP-hr	BACT-PSD
AK-0083	Kenai Nitrogen Operations	AGRIUM U.S. INC.	1/6/2015	2.7	MMBtu/hr	None	0.36	lb/MMBtu	BACT-PSD

Table D-6 Addendum: RBLC Results for Emergency Diesel Fire Pump
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
Nitrogen Dioxide									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP	3.6	G/HP-HR	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	4.41	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	260	HP	GCP	2.98	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	2.98	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	440	HP	GCP	2.98	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	2.98	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	61	HP	GCP	3.5	G/HP-HR	BACT
*LA-0370	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER LLC	04/27/2020	1.1	MM BTU/hr	CBF	1.15	LB/HR	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	1.66	MMBTU/H	GCP	3	G/BHP-H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	2.64	LB/H	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	158	HP		0.104	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	4.8	G/HP-H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	3	G/HP-HR	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0.22	mmBTU/hr	GCP	4.7	G/KWH	BACT
Carbon Monoxide									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP	3.3	G/HP-HR	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	0.95	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	420	horsepower		3.5	G/KW-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	260	HP	GCP	2.61	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	2.61	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	440	HP	GCP	2.61	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	2.61	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	61	HP	GCP	3.73	G/HP-HR	BACT
*LA-0370	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER LLC	04/27/2020	1.1	MM BTU/hr	GCP	0.4	LB/HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	2.5	MMBTU/H	GCP	2.6	G/HP-H	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	1.66	MMBTU/H	GCP	2.6	G/BHP-H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	2.5	MMBTU/H	GCP	2.6	G/HP-H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	2.31	LB/H	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	0.5	G	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	0.5	G	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	387	GRAM	BACT
TX-0889	SWEENY OLD OCEAN FACILITIES	CHEVRON PHILLIPS CHEMICAL COMPANY LP	08/08/2020	0		GCP	100	HR/YR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	2.6	G/HP-H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	2.6	G/HP-H	BACT
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0.22	mmBTU/hr	GCP	5	G/KWH	BACT
Volatile Organic Compounds									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP/CBF	0.19	G/HP-HR	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	0.36	LB/MMBTU	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	2.64	LB/H	BACT
OK-0181	WILDHORSE TERMINAL	KEYERA ENERGY INC	09/11/2019	0		GCP	3	GM/HP-HR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.11	G/HP-HR	BACT
*WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	GREEN BAY PACKAGING INC. â€“MILL DIVISION	04/01/2019	0			200	HOURS	BACT
Greenhouse Gases - Carbon Dioxide Equivalents									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP	163.6	LB/MMBTU	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	164	LB/MMBTU	BACT
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	12/31/2018	420	horsepower		241	TONS/YEAR	BACT
*LA-0370	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER LLC	04/27/2020	1.1	MM BTU/hr	GCP	9	TPY	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	2.5	MMBTU/H	GCP/energy efficiency measures.	20	T/YR	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	1.66	MMBTU/H	GCP	13.58	T/YR	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	2.5	MMBTU/H	CBF/GCP/energy efficiency measures.	20	T/YR	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	23	T/YR	BACT
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	158	HP	GCP	181.7	LB/H	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	10	TONS	BACT
*PA-0326	SHELL POLYMERS MONACA SITE	SHELL CHEMICAL APPALACHIA LLC	02/18/2021	0		GCP	10	TONS	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	1203	T/YR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	106	T/YR	BACT
*WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	GREEN BAY PACKAGING INC. â€“MILL DIVISION	04/01/2019	0			200	HOURS	BACT

(a) GCP = good combustion practices, CBF = clean burning fuels

Table D-6 Addendum: RBLC Results for Emergency Diesel Fire Pump
Updated Data: November 2018 to October 2021

RBLC ID	Facility Name	Company Name	Permit Date	Throughput	Units	Controls[A]	Emission Limit	Units	Type
PM_{10} (total)									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP/CBF	0.19	G/HP-HR	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	0.31	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	260	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	440	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	61	HP	GCP	0.3	G/HP-HR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	350	HP	GCP	0.15	G/HP-HR	BACT
*LA-0370	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER LLC	04/27/2020	1.1	MM BTU/hr	CBF	0.04	LB/HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	2.5	MMBTU/H	CBF/GCP	0.12	LB/H	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	1.66	MMBTU/H	GCP	0.57	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	2.5	MMBTU/H	CBF/GCP	0.12	LB/H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	0.13	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
PM_{10} (filterable only)									
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	158	HP	GCP	5.22	X10-3 LB/H	BACT
$PM_{2.5}$ (total)									
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	08/13/2020	19.4	gph	GCP/CBF	0.19	G/HP-HR	BACT
*AK-0086	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	03/26/2021	2.7	MMBtu/hr	GCP	0.31	LB/MMBTU	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	260	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	440	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	190	HP	GCP	0.15	G/HP-HR	BACT
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	07/23/2020	61	HP	GCP	0.3	G/HP-HR	BACT
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	04/19/2021	350	HP	GCP	0.15	G/HP-HR	BACT
*LA-0370	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER LLC	04/27/2020	1.1	MM BTU/hr	CBF	0.04	LB/HR	BACT
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	12/21/2018	2.5	MMBTU/H	CBF/GCP	0.12	LB/H	BACT
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	11/26/2019	1.66	MMBTU/H	GCP	0.57	LB/H	BACT
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	01/07/2021	2.5	MMBTU/H	CBF/GCP	0.12	LB/H	BACT
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	402	HP	GCP	0.13	LB/H	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.15	G/HP-HR	BACT
$PM_{2.5}$ (Filterable)									
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	02/06/2019	158	HP	GCP	5.22	X10-3 LB/H	BACT
Sulfuric Acid Mist									
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	H/YR	GCP/high efficiency design/CBF	0.0001	LB/MMBTU	BACT
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	06/24/2019	500	HR/YR	GCP/high efficiency design/CBF	0.0001	LB/MMBTU	BACT
Opacity									
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	01/28/2019	0.22	mmBTU/hr	GCP	10	% OPACITY	BACT

(a) GCP = good combustion practices, CBF = clean burning fuels

Table D-7

~~Table 2-4.~~ **RBLC Listings for Circuit Breaker Equipment Leaks**

RBLC ID	Facility Name	State	Permit Date	Pollutant	BACT Level	BACT Units	Control
*VA-0332	Chickahominy Power LLC	VA	6/24/2019	CO_2e	0.5	% Leak Rate	Low-pressure detection system (with alarm)
TX-0748	FGE Power, FGE Texas Project	TX	4/28/2014	CO_2e	0.5	% Leak Rate	Low pressure alarm and a low
VA-0319	Gateway Cogeneration 1, LLC - Smart Water Project	VA	8/27/2012	CO_2e	1.0	% Leak Rate	Enclosed pressure circuit breaker.
VA-0328	C4GT, LLC	VA	4/26/2018	CO_2e	0.5	% Leak Rate	Enclosed-pressure design with low-pressure detection system (with alarm).
*IL-0130	Jackson Energy Center	IL	12/31/2018	SF_6	0.5	% Leak Rate	Not specified
FL-0355	Fort Myers Plant	FL	9/10/2015	SF_6	0.5	% Leak Rate	Leakage detection systems and alarms.
FL-0356	Okeechobee Clean Energy Center	FL	3/9/2016	SF_6	0.5	% Leak Rate	Leakage detection systems and alarms.
IA-0107	Marshalltown Generating Station	IA	4/14/2014	SF_6	0.5	% Leak Rate	Not specified
IL-0129	CPV Three Rivers Energy Center	IL	7/30/2018	SF_6	0.5	% Leak Rate	Not specified
IN-0158	St. Joseph Energy Center, LLC	IN	12/3/2012	SF_6	0.5	% Leak Rate	A density alarm for leak detection and the use of totally enclosed and pressurized circuit breakers
MD-0041	CPV St. Charles	MD	4/23/2014	SF_6	0.5	% Leak Rate	Designed to meet ANSI c37.013 or equivalent to detect and minimize SF6 leaks
TX-0612	Thomas C. Ferguson Power Plant	TX	11/10/2011	SF_6	0.006	lb/hr	Not specified
CA-1212	Palmdale Hybrid Power Project	CA	10/18/2011	CO_2e	0.85	lbs SF_6/yr	Not specified
CA-1223	Pio Pico Energy Center	CA	11/19/2012	CO_2e	3.56	lbs SF_6/yr	Enclosed
KS-0029	The Empire District Electric Company	KS	7/14/2015	CO_2e	0.61	lbs SF_6/yr	Density (leak detection) alarms
TX-0824	Jackson County Generating Facility	TX	6/30/2017	CO_2e	3.04	lbs SF_6/yr	Totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout
PA-0309	Lackawanna Energy Ctr/Jessup	PA	12/23/2015	SF_6	6.00	lbs SF_6/yr	State-of-the-art sealed enclosed-pressure circuit breakers with leak detection
PA-0310	CPV Fairview Energy Center	PA	9/2/2016	SF_6	1500	ppm	Not specified

RBLC ID	Facility Name	State	Permit Date	Pollutant	BACT Level	BACT Units	Control
TX-0749	Golden Spread Electric Cooperative, Antelope Station	TX	6/2/2014	CO_2e	Not specified		Pressure lockout.
TX-0753	Guadalupe Generating Station	TX	12/2/2014	CO_2e	Not specified		Low pressure alarm and a low pressure lockout
TX-0757	Indeck Wharton Energy Center	TX	5/12/2014	CO_2e	Not specified		Low pressure alarm and a low pressure lockout
TX-0758	Ector County Energy Center	TX	8/1/2014	CO_2e	Not specified		Low pressure alarm and a low pressure lockout
*MD-0042	Wildcat Point Generation Facility	MD	4/8/2014	SF_6	Unspecified Manufacturer Provided Leak Rate		State-of-the-art circuit breakers
MD-0045	Mattawoman Energy Center	MD	11/13/2015	SF_6	Unspecified Manufacturer Provided Leak Rate		Designed to meet ANSI c37.013 or equivalent to detect and minimize SF6 leaks
MD-0046	Keys Energy Center	MD	10/31/2014	SF_6	Unspecified Manufacturer Provided Leak Rate		Designed to meet ANSI c37.013 or equivalent to detect and minimize SF6 leaks

Table D-7 Addendum: RBLC Listings for Circuit Breaker Equipment Leaks
Updated Data: February 2020 to October 2021

RBLC ID	Facility Name	State	Permit Date	Pollutant	BACT Level	BACT Units	Controls
IL-0130	JACKSON ENERGY CENTER	IL	12/31/2018	Sulfur Hexafluoride	0.5%	Leak Rate	
VA-0332	CHICKAHOMINY POWER LLC	VA	06/24/2019	Carbon Dioxide Equivalent (CO2e)	0.5%	Leak Rate	Enclosed-pressure design with low-pressure detection system (with alarm).

Table D-8

~~Table D-1:~~ RBLC Results for Piping Fugitives

From January 2021 Application

RBLC ID	Facility Name	Permit Date	Process Name	Pollutant	Control Method	Emission Limit	Limit Units
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	11/29/2012	Natural Gas Fugitives	CO2	--	0.29	tpy
TX-0753	GUADALUPE GENERATING STATION	12/2/2014	Components Fugitive Leak Emissions	CO2e	AVO	--	--
TX-0757	INDECK WHARTON ENERGY CENTER	5/12/2014	Components Fugitive Leak Emissions	CO2e	AVO	--	--
TX-0758	ECTOR COUNTY ENERGY CENTER	8/1/2014	Components Fugitive Leaks	CO2e	AVO	--	--
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	Equipment Leaks	CO2e	AVO	--	--
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/2015	Equipment Leaks	CO2e	AVO	--	--
MD-0046	KEYS ENERGY CENTER	10/31/2014	Equipment Leaks	CO2e	AVO	--	--
MD-0041	CPV ST. CHARLES	4/23/2014	Fugitive Emissions	CO2e	AVO	72.7	tpy
TX-0824	JACKSON COUNTY GENERATING FACILITY	6/30/2017	Natural Gas Fugitives	CO2e	AVO	693.3	tpy
VA-0328	C4GT, LLC	4/26/2018	Equipment Leaks from Natural Gas Components	CO2e	LDAR	--	--
TX-0748	FGE POWER, FGE TEXAS PROJECT	4/28/2014	Natural Gas Fugitive Emission Sources	CO2e	LDAR	--	--
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	11/29/2012	Natural Gas Fugitives	Methane	--	7.44	tpy
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Natural Gas Piping and Components	Methane	LDAR	4.3	tpy

Table D-8 Addendum: RBLC Results for Piping Fugitives
Updated Data: February 2021 to October 2021

RBLC ID	Facility Name	Permit Date	Process Name	Pollutant	Control Method	Emission Limit	Limit Units
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Natural Gas Piping and Components	Methane	(LDAR)/, use of ‘‘leakless‘‘ components.	4.3	TONS/YEAR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Fugitive Emissions (P807)	Volatile Organic Compounds (VOC)	Enhanced connector monitoring requirements to the most stringent leak detection and repai	99.38	T/YR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Fugitive Emissions (P807)	Carbon Dioxide Equivalent (CO2e)	i.an LDAR program for leaks of methane from equipment and piping components in tail gas (f	35	T/YR
TX-0886	MONT BELVIEU NGL FRACTIONATION UNIT	03/31/2020	EQUIPMENT LEAK FUGITIVES	Volatile Organic Compounds (VOC)	28 LAER leak detection and repair (LDAR) program	0	
VA-0332	CHICKAHOMINY POWER LLC	06/24/2019	Equipment Leaks from Natural Gas Components	Carbon Dioxide Equivalent (CO2e)	Best management practices to prevent, detect and repair leaks of natural gas from the pipin	0	
*TX-0908	NEWMAN POWER STATION	08/27/2021	Fugitives	Volatile Organic Compounds (VOC)	weekly AVO	0	
*TX-0908	NEWMAN POWER STATION	08/27/2021	Fugitives	Carbon Dioxide Equivalent (CO2e)	weekly AVO	0	
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	09/09/2019	Fugitive Components	Volatile Organic Compounds (VOC)	28LAER & 28PI	500	PPMV
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	09/09/2019	Fugitive Components	Carbon Dioxide Equivalent (CO2e)	LDAR	500	PPMV

Table D-9
~~Table D-2:~~ RBLC Results for Haul Road Fugitives

From January 2021 Application

RBLC ID	Facility Name	Permit Date	Process Name	Pollutant	Control Method	Emission Limit	Limit Units
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	11/3/2017	Haul Roads	PM10-filterable	Good Housekeeping Practices	0.03	LB/VMT
OH-0376	IRONUNITS LLC - TOLEDO HBI	2/9/2018	Haul Roads-Paved	PM10-filterable	Water Flushing and Sweeping	0.63	T/YR
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012	Haul Roads	PM10-total	Paving, wet/chemical suppression	--	--
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	7/12/2013	Haul Roads	PM10-total	Paving, wet/chemical suppression	--	--
IN-0263	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	Paved Roads and Parking Lots	PM10-total	Paving, wet/chemical suppression	--	--
MD-0046	KEYS ENERGY CENTER	10/31/2014	Haul Roads-Paved and Unpaved	PM10-total	Water Flushing and Sweeping	--	--
IN-0166	INDIANA GASIFICATION, LLC	6/27/2012	Haul Roads-Paved	PM10-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0173	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM10-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0179	OHIO VALLEY RESOURCES, LLC	9/25/2013	Paved Roads and Parking Lots	PM10-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0180	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM10-total	Paving, wet/chemical suppression	90	% CONTROL
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Haul Roads	PM10-total	Paving, wet/chemical suppression, speed re	0.38	T/YR
OH-0368	PALLAS NITROGEN LLC	4/19/2017	Haul Roads-Paved	PM10-total	Paving	2.6	T/YR
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	11/3/2017	Haul Roads	PM2.5-filterable	Good Housekeeping Practices	0.01	LB/VMT
OH-0376	IRONUNITS LLC - TOLEDO HBI	2/9/2018	Haul Roads-Paved	PM2.5-filterable	Water Flushing and Sweeping	0.15	T/YR
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012	Haul Roads	PM2.5-total	Paving, wet/chemical suppression	--	--
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	7/12/2013	Haul Roads	PM2.5-total	Paving, wet/chemical suppression	--	--
IN-0263	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	Paved Roads and Parking Lots	PM2.5-total	Paving, wet/chemical suppression	--	--
IN-0166	INDIANA GASIFICATION, LLC	6/27/2012	Haul Roads-Paved	PM2.5-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0173	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM2.5-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0179	OHIO VALLEY RESOURCES, LLC	9/25/2013	Paved Roads and Parking Lots	PM2.5-total	Paving, wet/chemical suppression	90	% CONTROL
IN-0180	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM2.5-total	Paving, wet/chemical suppression	90	% CONTROL
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Haul Roads	PM2.5-total	Paving, wet/chemical suppression, speed re	0.09	T/YR
MD-0046	KEYS ENERGY CENTER	10/31/2014	Haul Roads-Paved and Unpaved	PM-filterable	Water Flushing and Sweeping	--	--
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	5/12/2016	Haul Roads	PM-filterable	Vacuum sweeping/washing	--	--
IN-0166	INDIANA GASIFICATION, LLC	6/27/2012	Haul Roads-Paved	PM-filterable	Paving, wet/chemical suppression	90	% CONTROL
IN-0173	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM-filterable	Paving, wet/chemical suppression	90	% CONTROL
IN-0179	OHIO VALLEY RESOURCES, LLC	9/25/2013	Paved Roads and Parking Lots	PM-filterable	Paving, wet/chemical suppression	90	% CONTROL
IN-0180	MIDWEST FERTILIZER CORPORATION	6/4/2014	Paved Roads and Parking Lots	PM-filterable	Paving, wet/chemical suppression	90	% CONTROL
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	11/3/2017	Haul Roads	PM-filterable	Good Housekeeping Practices	0.13	LB/VMT
KY-0100	J.K. SMITH GENERATING STATION	4/9/2010	Haul Roads	PM-fugitive	Paving, wet/chemical suppression	--	--
MD-0041	CPV ST. CHARLES	4/23/2014	Haul Roads	PM-fugitive	--	--	--
OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Haul Roads	PM-fugitive	Paving	--	--
MD-0042	WILDCAT POINT GENERATION FACILITY	4/8/2014	Haul Roads-Paved and Unpaved	PM-fugitive	Reasonable precautions	--	--
OH-0332	MIDDLETOWN COKE COMPANY	2/9/2010	Paved Roads and Parking Lots	PM-fugitive	Watering	1.08	T/YR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Haul Roads	PM-fugitive	Paving, wet/chemical suppression, speed re	1.88	T/YR
OH-0368	PALLAS NITROGEN LLC	4/19/2017	Haul Roads-Paved	PM-fugitive	Paving	13.2	T/YR
OH-0345	DP&L J.M. STUART GENERATING STATION	8/16/2011	Haul Roads-Paved	PM-fugitive	Watering, speed restrictions	110.96	T/YR
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012	Haul Roads	PM-total	Paving, wet/chemical suppression	--	--
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	7/12/2013	Haul Roads	PM-total	Paving, wet/chemical suppression	--	--
IN-0263	MIDWEST FERTILIZER COMPANY LLC	3/23/2017	Paved Roads and Parking Lots	PM-total	Paving, wet/chemical suppression	--	--
IL-0129	CPV THREE RIVERS ENERGY CENTER	7/30/2018	Haul Roads	PM-total	Paving	10	% OPACITY
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Haul Roads	PM-total	--	10	% OPACITY

Table D-9 Addendum: RBLC Results for Haul Road Fugitives
Updated Data: February 2021 to October 2021

RBLC ID	Facility Name	Permit Date	Process Name	POLLUTANT	Control Method	Emission Limit	Limit Units
IL-0130	JACKSON ENERGY CENTER	12/31/2018	Roadways	Particulate matter, total (TPM)		10	PERCENT OPACITY
KY-0110	NUCOR STEEL BRANDENBURG	07/23/2020	EP 14-01 - Paved Roadways	Particulate matter, fugitive	surface improvements/sweeping & watering	0	
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	Particulate matter, filterable (FPM)	Sweeping & Watering	0	
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	Particulate matter, total < 10 Âµ (TPM10)	Sweeping & Watering	0	
KY-0115	NUCOR STEEL GALLATIN, LLC	04/19/2021	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Sweeping & Watering	0	
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Facility Roadways (F001)	Particulate matter, fugitive	Paving/Sweeping & Watering	1.88	T/YR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Facility Roadways (F001)	Particulate matter, total < 10 Âµ (TPM10)	Paving/Sweeping & Watering	0.38	T/YR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Facility Roadways (F001)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Paving/Sweeping & Watering	0.09	T/YR
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	12/21/2018	Facility Roadways (F001)	Visible Emissions (VE)	Paving/Sweeping & Watering	0	
OH-0379	PETMIN USA INCORPORATED	02/06/2019	Plant Roadways (F001)	Particulate matter, total < 10 Âµ (TPM10)	Watering	0.21	T/YR
OH-0379	PETMIN USA INCORPORATED	02/06/2019	Plant Roadways (F001)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Watering	0.02	T/YR
OH-0379	PETMIN USA INCORPORATED	02/06/2019	Plant Roadways (F001)	Visible Emissions (VE)	Watering	0	

APPENDIX E – ECONOMIC TABLES

Table E-1a
SCR System Capital Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$350,000**	A = SCR system cost
Instrumentation	$35,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$17,500	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$402,500**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$120,750	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required
Total Direct Cost (DC)	**$523,250**	1.30B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$40,250	0.10 x B
Construction and field expenses	$20,125	0.05 x B
Contractor fees	$40,250	0.10 x B
Start-up	$8,050	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$20,125	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$136,300**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$659,550**	1.62B + Performance test + Other + SP + Bldg.

Table E-1b
SCR System Annual Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	23,429	ISO Rating
Power Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	70.29	
Unit cost ($/kWh)	$0.045	Estimated market value
Cost of Power Loss ($/yr)	$27,707	Based on operation 8760 hours/yr
Operating Labor		
Catalyst labor req.	$16,425	1/2 hr/shift @ $30/hr
Ammonia delivery requirement (SCR)	$720	24 hr/yr (3 deliveries per year) @ $30/hr
Ammonia recordkeeping and reporting (SCR)	$1,200	40 hours per year @ $30/hr
Catalyst cleaning	$1,200	40 hours per year @ $30/hr
Supervisor	$2,464	15% Operating labor
Total Cost ($/yr)	$22,009	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr (8 workers, 40 hr, every 3 years, $30/hr)
Catalyst system maintenance labor req.	$16,425	1/2 hr/shift @ $30/hr
Ammonia system maintenance labor req.	$10,950	1 hr/day @ $30/hr
Material	$27,375	100% of maintenance labor
Total Cost ($/yr)	$57,950	
Ammonia		
Requirement (tons/yr)	33.7	29% aqueous ammonia @ $375/ton
Unit Cost ($/ton)	$375	Estimate
Total Cost ($/yr)	$12,654	
Process Air		
Requirement (scf/lb NH_3)	350	
Requirement (mscf/yr)	103,463	
Unit Cost ($/mscf)	$0.20	$0.20 per 1000 scf
Total Cost ($/yr)	$20,693	
Catalyst		
Catalyst Cost ($)	$35,000	Catalyst modules
Catalyst Disposal Cost ($)	$38	Disposal of catalyst modules
Sales Tax ($)	$0	Pollution Control Equipment Exempt
Catalyst Life (yrs)	3	n
Interest Rate (%)	7.0%	i
CRF	0.381	Amortization of catalyst for 3 yrs
Total Cost ($/yr)	$13,351	(Volume) * (Unit Cost) * (CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$62,257	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$62,257	
Total Annualized Costs (TAC) ($)	**$216,620**	
Total NOx Controlled (ton/yr)	14.2	90% reduction
COST EFFECTIVENESS ($/ton)	**$15,264**	

Table E-2a
Ultra-Low NOx Burner System Capital Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$115,000**	A
Instrumentation	$11,500	0.10 x A
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$5,750	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$132,250**	B = 1.15 x A
Direct Installation Costs		
Electrical	$5,290	0.04 x B
Insulation for ductwork	$1,323	0.01 x B
Painting	$1,323	0.01 x B
Total Direct Installation Cost	$7,935	0.06 x B
Total Direct Cost (DC)	**$140,185**	1.06B
Indirect Costs (Installation)		
Start-up	$2,645	0.02 x B
Performance test	$1,323	0.01 x B
Contingencies	$6,613	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$10,580**	0.08B + Other
Total Capital Investment (TCI) = DC + IC	**$150,765**	1.14B + Other

Table E-2b
Ultra-Low Nox Burner System Annual Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Annual Costs (DC)		
Operating Labor		
Operating Labor	$19,163	1/2 hr/shift @ $35/hr, 375 shifts/year
Supervisor	$2,874	15% Operating labor
Total Cost ($/yr)	$22,037	
Maintenance		
Auxiliary boiler burner maintenance labor req.	$3,210	107 hr/y (8 worker, 40 hr, every 3 years), $30/hr
Material	$3,210	100% of maintenance labor
Total Cost ($/yr)	$6,420	
Indirect Annual Costs (IC)		
Overhead	$13,222.13	60% labor
Administrative charges	$3,015	2% TCI
Annual Contingency	$7,009	5% of DC
Property taxes	$1,508	1% TCI
Insurance	$1,508	1% TCI
Capital Recovery	$12,150	CRF x TCI (30 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$38,412	
Total Annualized Costs (TAC) ($)	**$66,868**	
Total Pollutant Controlled (ton/yr) (Natural Gas)	11.3	30 ppm controlled to 9 ppm
COST EFFECTIVENESS ($/ton)	**$5,895**	

Table E-3a
Oxidation Catalyst Capital Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$75,000**	A
Instrumentation	$7,500	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$3,750	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$86,250**	B = 1.15 x (A)
Direct Installation Costs		
Foundations and supports	$6,900.00	0.08 x B
Handling and erection	$12,075	0.14 x B
Electrical	$3,450	0.04 x B
Piping	$1,725	0.02 x B
Insulation for ductwork	$863	0.01 x B
Painting	$863	0.01 x B
Total Direct Installation Cost	$25,875	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required (5-18% PEC)
Total Direct Cost (DC)	**$112,125**	1.3B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$8,625	0.10 x B
Construction and field expenses	$4,313	0.05 x B
Contractor fees	$8,625	0.10 x B
Start-up	$1,725	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$4,313	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$35,100**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$147,225**	1.62B + Performance test + Other + SP + Bldg.

Table E-3b
Oxidation Catalyst Annual Cost Analysis - Auxiliary Boiler

Item	Value	Basis
Direct Annual Costs (DC)		
Steam		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	23,429	ISO Rating
Output Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Output Loss Due to Pressure Drop (kW)	70.29	
Unit cost ($/kWh)	$0.05	Current Purchase Price
Cost of Heat Rate Loss ($/yr)	$27,707	Based on operation 8,760 hours/yr
Operating Labor		Assumed $30/hr
Catalyst labor req.	$16,425	216 hr/yr (1/2 hr/shift. 1095 shifts/yr)
Supervisor	$2,464	15% Operating labor
Total Cost ($/yr)	$18,889	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr(8 worker, 40 hr, every 3 years)
Material	$3,200	100% of maintenance labor
Total Cost ($/yr)	$6,400	
Catalyst		
Catalyst Cost ($)	$35,000	Catalyst modules
Catalyst Disposal Cost ($)	$1,500	Disposal of catalyst modules
Sales Tax ($)	$0	Assume exempt from taxes
Catalyst Life (yrs)	3	n
Interest Rate (%)	7%	I
CRF	0.381	Amortization of catalyst over 3 yrs
Total Cost ($/yr)	$13,908	(Volume)(Unit Cost)(CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$13,897	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$13,897	
Total Annualized Costs (TAC) ($)	$80,801	
Total CO Controlled (ton/yr)	14.6	90% removal
Total VOC Controlled (ton/yr)	1.2	50% removal
COST EFFECTIVENESS ($/ton)	**$5,125**	

Table 1a
Ultra-Low NOx Burner System Capital Cost Analysis - Natural Gas Heater

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$20,000**	A
Instrumentation	$2,000	0.10 x A
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$1,000	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$23,000**	B = 1.15 x A
Direct Installation Costs		
Electrical	$920	0.04 x B
Insulation for ductwork	$230	0.01 x B
Painting	$230	0.01 x B
Total Direct Installation Cost	$1,380	0.06 x B
Total Direct Cost (DC)	**$24,380**	1.06 x B
Indirect Costs (Installation)		
Start-up	$460	0.02 x B
Performance test	$0	Assumed not required
Contingencies	$1,150	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$1,610**	0.07B + Other
Total Capital Investment (TCI) = DC + IC	**$25,990**	1.13B + Other

Table 1b
Ultra-Low NOx Burner System Annual Cost Analysis - Natural Gas Heater

Item	Value	Basis
Direct Annual Costs (DC)		
Operating Labor		
Operating Labor	$6,388	1/2 hr/shift @ $35/hr, 365 shifts/year
Supervisor	$958	15% Operating labor
Total Cost ($/yr)	$7,346	
Maintenance		
Heater burner maintenance labor req.	$3,210	107 hr/y (8 worker, 40 hr, every 3 years), $30/hr
Material	$3,210	100% of maintenance labor
Total Cost ($/yr)	$6,420	
Indirect Annual Costs (IC)		
Overhead	$4,407.38	60% labor
Administrative charges	$520	2% TCI
Annual Contingency	$1,219	5% of DC
Property taxes	$260	1% TCI
Insurance	$260	1% TCI
Capital Recovery	$2,094	CRF x TCI (30 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$8,760	
Total Annualized Costs (TAC) ($)	**$22,526**	
Total Pollutant Controlled (ton/yr) (Natural Gas)	1.7	80% Reduction
COST EFFECTIVENESS ($/ton)	**$13,187**	

Table E-3a
SCR System Capital Cost Analysis - Gas Heater

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$70,000**	A (SCR system cost)
Instrumentation	$7,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$3,500	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$80,500**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$24,150	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required
Total Direct Cost (DC)	**$104,650**	1.30B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$8,050	0.10 x B
Construction and field expenses	$4,025	0.05 x B
Contractor fees	$8,050	0.10 x B
Start-up	$1,610	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$4,025	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$33,260**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$137,910**	1.62B + Performance test + Other + SP + Bldg.

Table E-3b
SCR System Capital Cost Analysis - Gas Heater

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	2,343	ISO Rating
Power Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	7.03	
Unit cost ($/kWh)	$0.045	Estimated market value
Cost of Power Loss ($/yr)	$2,771	Based on operation 8,760 hours/yr
Operating Labor		
Catalyst labor req.	$16,425	1/2 hr/shift @ $30/hr
Ammonia delivery requirement (SCR)	$720	24 hr/yr (3 deliveries per year) @ $30/hr
Ammonia recordkeeping and reporting (SCR)	$1,200	40 hours per year @ $30/hr
Catalyst cleaning	$1,200	40 hours per year @ $30/hr
Supervisor	$2,464	15% Operating labor
Total Cost ($/yr)	$22,009	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr (8 workers, 40 hr, every 3 years)
Catalyst system maintenance labor req.	$16,425	1/2 hr/shift @ $30/hr
Ammonia system maintenance labor req.	$10,950	1 hr/day @ $30/hr
Material	$27,375	100% of maintenance labor
Total Cost ($/yr)	$57,950	
Ammonia		
Requirement (tons/yr)	4.6	29% aqueous ammonia @ $375/ton
Unit Cost ($/ton)	$375	Estimate
Total Cost ($/yr)	$1,722	
Process Air		
Requirement (scf/lb NH_3)	350	
Requirement (mscf/yr)	14,082	
Unit Cost ($/mscf)	$0.20	$0.20 per 1000 scf
Total Cost ($/yr)	$2,816	
Catalyst		
Catalyst Cost ($)	$8,500	Catalyst modules
Catalyst Disposal Cost ($)	$38	Disposal of catalyst modules
Sales Tax ($)	$0	Pollution Control Equipment Exempt
Catalyst Life (yrs)	3	n
Interest Rate (%)	7.0%	i
CRF	0.381	Amortization of catalyst for 3 yrs
Total Cost ($/yr)	$3,253	(Volume) * (Unit Cost) * (CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$13,018	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$13,018	
Total Annualized Costs (TAC) ($)	**$103,539**	
Total NOx Controlled (ton/yr)	1.9	90% reduction
COST EFFECTIVENESS ($/ton)	**$53,604**	

Table E-4a
CO Catalyst Capital Cost Analysis - Gas Heater

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$14,000**	A
Instrumentation	$1,400	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$700	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$16,100**	B = 1.15 x (A)
Direct Installation Costs		
Foundations and supports	$1,288.00	0.08 x B
Handling and erection	$2,254	0.14 x B
Electrical	$644	0.04 x B
Piping	$322	0.02 x B
Insulation for ductwork	$161	0.01 x B
Painting	$161	0.01 x B
Total Direct Installation Cost	$4,830	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required (5-18% PEC)
Total Direct Cost (DC)	**$20,930**	1.3B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$1,610	0.10 x B
Construction and field expenses	$805	0.05 x B
Contractor fees	$1,610	0.10 x B
Start-up	$322	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$805	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$12,652**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$33,582**	1.62B + Performance test + Other + SP + Bldg.

Table E-4b
CO Catalyst Annual Cost Analysis - Gas Heater

Item	Value	Basis
Direct Annual Costs (DC)		
Steam		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	2,343	ISO Rating
Output Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Output Loss Due to Pressure Drop (kW)	7.03	
Unit cost ($/kWh)	$0.05	Current Purchase Price
Cost of Heat Rate Loss ($/yr)	$2,771	Based on operation 8,760 hours/yr
Operating Labor		Assumed $30/hr
Catalyst labor req.	$16,425	216 hr/yr (1/2 hr/shift. 431 shifts/yr)
Supervisor	$2,464	15% Operating labor
Total Cost ($/yr)	$18,889	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr(8 worker, 40 hr, every 3 years)
Material	$3,200	100% of maintenance labor
Total Cost ($/yr)	$6,400	
Catalyst		
Catalyst Cost ($)	$8,000	Catalyst modules
Catalyst Disposal Cost ($)	$1,500	Disposal of catalyst modules
Sales Tax ($)	$0	Assume exempt from taxes
Catalyst Life (yrs)	3	n
Interest Rate (%)	7%	I
CRF	0.381	Amortization of catalyst over 3 yrs
Total Cost ($/yr)	$3,620	(Volume)(Unit Cost)(CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$3,170	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$3,170	
Total Annualized Costs (TAC) ($)	$34,849	
Total CO Controlled (ton/yr)	3.2	90% removal
Total VOC Controlled (ton/yr)	0.07	
COST EFFECTIVENESS ($/ton)	**$10,550**	

Table 1
Oxidation Catalyst Capital Cost Analysis - Emergency Fire Pump

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$11,895**	A
Instrumentation	$1,190	0.10 x A
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$595	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$13,679**	B = 1.15 x A
Direct Installation Costs		
Foundations and supports	$1,094	0.08 x B
Handling and erection	$1,915	0.14 x B
Electrical	$547	0.04 x B
Piping	$274	0.02 x B
Insulation for ductwork	$137	0.01 x B
Painting	$137	0.01 x B
Total Direct Installation Cost	$4,104	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required (5-18% PEC)
Total Direct Cost (DC)	**$17,783**	1.3B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$1,368	0.10 x B
Construction and field expenses	$684	0.05 x B
Contractor fees	$1,368	0.10 x B
Start-up	$274	0.02 x B
Performance test	$1,500	Stack Test Vendor Quote
Contingencies	$684	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$5,877**	0.32B + Other + Performance Test
Total Capital Investment (TCI) = DC + IC	**$23,660**	1.62B + Performance Test + SP + Bldg

Table 2
Oxidation Catalyst Annual Cost Analysis - Emergency Fire Pump

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Black Start Engine (kW)	450	ISO Rating
Output Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Output Loss Due to Pressure Drop (kW)	1.35	
Unit cost ($/kWh)	$0.059	Current Purchase Price
Cost of Heat Rate Loss ($/yr)	$40	Based on operation of 500 hours/yr
Operating Labor		Assumed $30/hr
Catalyst labor	$938	1/2 hr per shift
Material	$938	100% of maintenance labor
Supervisor	$141	15% Operating labor
Total Cost ($/yr)	$2,016	
Catalyst		
Catalyst Cost ($)	$827	Catalyst modules
Catalyst Disposal Cost ($)	$38	Disposal of catalyst modules
Catalyst replacement labor	$3,200	107 hr/yr (8 worker, 40 hr, every 3 years)
Sales Tax ($)	$0	Assume exempt from taxes
Catalyst Life (yrs)	3	n
Interest Rate (%)	7%	I
CRF	0.381	Amortization of catalyst over 3 yrs
Total Cost ($/yr)	$1,549	(Material + Labor Costs) * CRF
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$2,233	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$2,233	
Total Annualized Costs (TAC) ($)	$5,838	
Total CO Controlled (ton/yr)	0.32	80% removal
Total VOC Controlled (ton/yr)	0.09	50% removal
COST EFFECTIVENESS ($/ton)	**$14,326**	

Table 3
SCR System Capital Cost Analysis - Emergency Generator

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$42,601**	A
Instrumentation	$4,260	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$2,130	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$48,991**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$14,697	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required
Total Direct Cost (DC)	**$63,688**	B + SP + Bldg. + Total Direct Install. Cost
Indirect Costs (Installation)		
Engineering	$4,899	0.10 x B
Construction and field expenses	$2,450	0.05 x B
Contractor fees	$4,899	0.10 x B
Start-up	$980	0.02 x B
Performance test	$1,500	Stack Test Vendor Quote
Contingencies	$2,450	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$17,177**	0.32B + Other + Performance Test
Total Capital Investment (TCI) = DC + IC	**$80,866**	1.32B + Perf. Test + SP + Bldg + DC

Table 4
SCR System Annual Cost Analysis - Emergency Generator

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Black Start (kW)	450	ISO Rating
Power Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	1.35	
Unit cost ($/kWh)	$0.059	Estimated market value
Cost of Power Loss ($/yr)	$40	Based on operation of 500 hours/yr
Operating Labor		
Catalyst labor req.	$938	1/2 hr/shift @ $30/hr
Ammonia delivery requirement (SCR)	$720	24 hr/yr (3 deliveries per year) @ $30/hr
Ammonia recordkeeping and reporting (SCR)	$1,200	10 hours per year @ $30/hr
Catalyst cleaning	$1,200	10 hours per year @ $30/hr
Supervisor	$141	15% Operating labor
Total Cost ($/yr)	$4,198	
Maintenance		
Catalyst replacement labor	$3,210	107 hr/yr (8 workers, 40 hr, every 3 years)
Catalyst system maintenance labor req.	$938	1/2 hr/shift @ $30/hr
Ammonia system maintenance labor req.	$10,950	1 hr/day @ $30/hr
Material	$11,888	100% of maintenance labor
Total Cost ($/yr)	$26,985	
Ammonia		
Requirement (tons/yr)	7.9	29% aqueous ammonia @ $375/ton
Unit Cost ($/ton)	$375	Estimate
Total Cost ($/yr)	$2,975	
Process Air		
Requirement (scf/lb NH_3)	350	
Requirement (mscf/yr)	24,323	
Unit Cost ($/mscf)	$0.20	$0.20 per 1000 scf
Total Cost ($/yr)	$4,865	
Catalyst		
Catalyst Cost ($)	$5,173	Catalyst modules
Catalyst Disposal Cost ($)	$38	Disposal of catalyst modules
Sales Tax ($)	$0	Pollution Control Equipment Exempt
Catalyst Life (yrs)	3	n
Interest Rate (%)	7.0%	i
CRF	0.381	Amortization of catalyst for 3 yrs
Total Cost ($/yr)	$1,986	(Volume) * (Unit Cost) * (CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$7,633	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$7,633	
Total Annualized Costs (TAC) ($)	**$48,681**	
Total Pollutant Controlled (ton/yr) (Natural gas)	3.3	85% reduction (Based on 500 hrs/yr)
COST EFFECTIVENESS ($/ton)	**$14,592**	

State of Wisconsin
DEPARTMENT OF NATURAL RESOURCES

Information Request

FID/Docket Number: 816127840 Date of Request: March 26, 2019

Requested From: WDNR Response Due: April 10, 2019

Contact Requesting Information: Megan Corrado, Air Management Engineer

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
017 (3.)	For the diesel generator, please provide the cost difference between a Tier 2 and Tier 4 engine as well as the associated dollar per ton of controlled emissions.

Response:

017 (3.)

For the diesel generator, the cost difference between a Tier 2 and a Tier 4 engine is summarized below and shown in detail in Attachment 2.

Parameter	Tier 2 Engine	Tier 4 Engine	Difference
Initial Capital Cost	$500,000	$950,000	$450,000
Total Capital Investment	$635,375	$1,207,213	$571,838
Total Annualized Costs	$105,368	$200,198	$94,831
Emissions Sum of NOx, PM, and VOC)	4.3 tons	3.1 tons	1.3 ton decrease
Cost per Ton for change from Tier 2 to Tier 4			$74,993

Due to the limited usage of the emergency generator and the cost of the Tier 4 engine, it is economically infeasible to install a Tier 4 engine.

Response by: Minda Nelson, P.E.
Title: Associate Environmental Engineer
Department: Burns & McDonnell
Telephone: (816) 822-4208

List Sources of Information:

Table 2a
Tier 2 Generator Capital Cost Analysis

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$500,000**	A
Instrumentation	$50,000	0.10 x A
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$25,000	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$575,000**	B = 1.15 x A
Direct Installation Costs		
Not applicable		
Total Direct Cost (DC)	**$575,000**	B
Indirect Costs (Installation)		
Start-up	$11,500	0.02 x B
Performance test	$0	Assumed not required
Contingencies	$28,750	0.05 x B
Other	$0	As required
Construction Period	0.5	Years (n)
Interest Rate	7.0	Percent (i)
Interest during construction (Int.)	$20,125	DC x i x n
Total Indirect Cost (IC)	**$60,375**	0.07B + Other + Int
Total Capital Investment (TCI) = DC + IC	**$635,375**	1.07B + Other + Int.

Tier 4 Generator Capital Cost Analysis

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$950,000**	A
Instrumentation	$95,000	0.10 x A
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$47,500	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$1,092,500**	B = 1.15 x A
Direct Installation Costs		
Not applicable		
Total Direct Cost (DC)	**$1,092,500**	B
Indirect Costs (Installation)		
Start-up	$21,850	0.02 x B
Performance test	$0	Assumed not required
Contingencies	$54,625	0.05 x B
Other	$0	As required
Construction Period	0.5	Years (n)
Interest Rate	7.0	Percent (i)
Interest during construction (Int.)	$38,238	DC x i x n
Total Indirect Cost (IC)	**$114,713**	0.07B + Other + Int
Total Capital Investment (TCI) = DC + IC	**$1,207,213**	1.07B + Other + Int.

Table 2b

Tier 2 Generator Annual Cost Analysis		
Item	**Value**	**Basis**
Direct Annual Costs (DC)		
Operating Labor		
Not applicable		
Maintenance		
Not applicable		
Indirect Annual Costs (IC)		
Overhead	$0	60% labor + materials
Administrative charges	$12,708	2% TCI
Annual Contingency	$28,750	5% of DC
Property taxes	$6,354	1% TCI
Insurance	$6,354	1% TCI
Capital Recovery	$51,203	CRF x TCI (30 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$105,368	
Total Annualized Costs (TAC) ($)	**$105,368**	

Tier 4 Generator Annual Cost Analysis		
Item	**Value**	**Basis**
Direct Annual Costs (DC)		
Operating Labor		
Not applicable		
Maintenance		
Not applicable		
Indirect Annual Costs (IC)		
Overhead	$0	60% labor + materials
Administrative charges	$24,144	2% TCI
Annual Contingency	$54,625	5% of DC
Property taxes	$12,072	1% TCI
Insurance	$12,072	1% TCI
Capital Recovery	$97,285	CRF x TCI (30 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$200,198	
Total Annualized Costs (TAC) ($)	**$200,198**	

Increase in Annualized Costs (Tier 2 vs Tier 4)	$94,831	
Nitrogen Oxides (NOx)	1.1	% Reduction
Particulate	0.09	% Reduction
Volatile Organic Compounds (VOC)	0.11	% Reduction
Total Pollutant Controlled (ton/yr)	1.3	Tier 4
COST EFFECTIVENESS ($/ton)	**$74,993.24**	

Cost Evaluation for Natural Gas Piping
Leak Detection and Repair (LDAR)

LDAR Cost Item	1992 Dollars	
Annualized Capital Charges - Instrumental LDAR		
Control Equipment		
Monitoring instrument	$1,495.00	
Compressor seal vent system	-	
Rupture disk (i.e., pressure relief device) (Unit A model cost)	$90.00	2 disks
Rupture disk	$360.00	8 disks
Rupture disk assembly	$1,256.00	2 disks
Closed-loop sampling (assume none)	$5,024.00	8 disks
Subtotal Annualized Capital Charges ($/year)	**$6,879.00**	
Operating Costs		
Annual Maintenance Charges - Instrumental LDAR		
Monitoring instrument	$4,280.00	
Compressor seal vent system		
Rupture disk (Unit A model cost)	$8.00	
Rupture disk	$32.00	
Rupture disk assembly (Unit A model cost)	$385.00	2 disks
Rupture disk assembly	$1,540.00	8 disks
Caps for open-ended lines (assume none)	$0.00	2 disks
Closed-loop sampling (assume none)	$0.00	8 disks
Replacement pump seals (assume none)	$0.00	
Subtotal Annual Maintenance Charges ($/year)	**$5,852.00**	
Annual Miscellaneous Charges (taxes, insurance, administration) - Instrumental LDAR		
Monitoring instrument	$260.00	
Compressor seal vent system		
Rupture disk assembly (Unit A model cost)	$314.00	2 disks
Rupture disk	$1,256.00	8 disks
Caps for open-ended lines (assume none)	$0.00	
Closed-loop sampling (assume none)	$0.00	
Replacement pump seals (assume none)	$0.00	
Subtotal Annual Miscellaneous Charges ($/year)	**$1,516.00**	
Labor Charges - Instrumental LDAR		
LDAR monitoring	$12,940	
Subsequent repair	$7,369	
Administrative and support	$8,124	
Subtotal Labor Charges ($/year)	$28,433	
Grand Total ($/year) - Jan. 1992 dollars - Instrumental LDAR	$42,680	
Total Annual Cost	2020 Dollars[b]	
Grand Total Cost of Instrumental LDAR ($/year)	$79,726	

(a) Cost information is from (Table 6-12) of Hazardous Air Pollutant Emissions from Process Units in the Synthetic Organic Chemical Manufacturing Industry – Background Information for Proposed Standards. Volume 1C: Model Emission Sources (EPA-453/D-92-016c). Nov. 1992. U.S. EPA. Unit A model facility costs utilized in the calculations. Costs are presented in 1992 dollars.

(b) Annual costs converted from 1992 to January 2020 values using the consumer price index. Web site used to compute 2020 dollars is located at:
https://inflationdata.com/Inflation/Inflation_Calculators/Cumulative_Inflation_Calculator.aspx

Cost Evaluation for Natural Gas Piping
Leak Detection and Repair (LDAR)

Cost Effectiveness Calculations	
Uncontrolled emission rate, CO_2e (ton/year)	976.6
Uncontrolled emission rate, mass greenhouse gas (GHG) (ton/year) [CO_2e/ GWP CH_4]	39.1
Uncontrolled emission rate, VOC (ton/year)	2.8
Total Uncontrolled emission rate, VOC + mass greenhouse gas (GHG) (ton/year)[a]	41.9
Average assumed control efficiency of instrumental LDAR (range is 30-97%)	56%
Mass GHG emission reduction from instrumental LDAR (ton/year)	23.45
Density of natural gas (pounds/standard cubic foot)[b]	0.0420
Volume GHG emission reduction from instrumental LDAR (standard cubic feet/year)	1,116,037
Value of natural gas ($/1000 standard cubic feet - 2019)[c]	2.99
Instrumental LDAR Cost Effectiveness	
Natural gas recovery savings from instrumental LDAR ($/year)	$3,337
Net annual cost of instrumental LDAR (grand total cost - savings) ($/year)	$76,389
Cost effectiveness of instrumentation LDAR, mass basis ($/ton GHG)	$3,258
Cost effectiveness of instrumental LDAR, carbon dioxide equivalent (CO_2e) basis ($/ton CO_2e)[d]	$130

(a) Total emissions evaluated does not include fuel oil VOC. The overall natural gas emissions (41.9 tpy) is greater than fuel oil emissions (7.58 tpy).

(b) Density of natural gas obtained from Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources (AP-42) . Appendix A. January 1995. U.S. EPA.

(c) 2019 value of natural gas for electric power production obtained from the United States Energy Information Administration: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm. Accessed on 15 January 2021

(d) Global warming potential (GWP) for methane used to convert the cost effectiveness from a mass basis to a CO_2e basis by dividing the mass based cost effectiveness by the GWP of methane. The GWP of methane is 25 according to 40 Code of Federal Regulations Part 98, Subpart
A, Table A-1.

From Post Application BACT evaluation on "leak-proof" Piping Components

Cost Analysis

Table 1
VOC Capital Cost Analysis - Certified Low Leaking Valve

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$100,000**	A
Instrumentation	$10,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$5,000	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$115,000**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$34,500	0.30 x B
Inspection access infrastructure	$475,037	
Total Direct Cost (DC)	**$624,537**	
Indirect Costs (Installation)		
Engineering	$11,500	0.10 x B
Construction and field expenses	$5,750	0.05 x B
Contractor fees	$11,500	0.10 x B
Start-up	$2,300	0.02 x B
Contingencies	$5,750	0.05 x B
Other	$0	As required
Construction Period	0	Years (n)
Interest Rate	7.0	Percent (i)
Interest during construction (Int.)	$0	DC x i x n
Total Indirect Cost (IC)	**$36,800**	0.32B + Other
Total Capital Investment (TCI) = DC + IC	**$661,337**	1.32B + SP + Bldg + DC

Table 2
VOC Annual Cost Analysis - Certified Low Leaking Valve

Item	Value	Basis
Direct Annual Costs (DC)		
Operating Labor		
Inspection labor req.	$57,350	5 min to inspect a valve monthly @ $50 /hr
Supervisor	$8,603	15% Operating labor
Cost for inspection infrastructure	$2,500	lifts and temporary scaffolding
Total Cost $/yr	$68,453	
Maintenance		
Valve replacement labor	$0	All valves replaced over 5 years, 10 hr/replacement
Material	$0	$2500 replacement cost/valve
Cost for replacement infrastructure	$0	lifts and temporary scaffolding
Total Cost $/yr	$0	
Indirect Annual Costs (IC		
Capital Recovery	$161,294	CRF x TCI 5 yr life, 7.0% interest
Total Indirect Costs $/yr	$161,294	
Total Annualized Costs (TAC) ($	**$229,746**	
Total Pollutant Controlled ton/yr VOC	7.7	80% reduction
COST EFFECTIVENESS $/ton	**$29,826**	$/ton VOC

95.58	inspection hours/month
$50	labor cost/hr
1,147	total valve count (NG and Oil)
229.40	valve/year replaced with 5 year life
5	year life
2,500	$/valve total for replacements not needed on baseline valves
80%	reduction
10	hr/replace a valve

Capital Recovery Factor

Interest	7.0%
Years	5

$$CRF = \frac{i * (1+i)^n}{1+i)^n - 1}$$

CRF = 0.243890694

100	Low leak valve ppm guarantee
500	Standard valve ppm guarantee

From Post Application BACT evaluation on "leak-proof" Piping Components
Cost Analysis

Table 1
Methane Capital Cost Analysis - Certified Low Leaking Valve

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$100,000**	A
Instrumentation	$10,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$5,000	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$115,000**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$34,500	0.30 x B
Inspection access infrastructure	$475,037	
Total Direct Cost (DC)	**$624,537**	
Indirect Costs (Installation)		
Engineering	$11,500	0.10 x B
Construction and field expenses	$5,750	0.05 x B
Contractor fees	$11,500	0.10 x B
Start-up	$2,300	0.02 x B
Contingencies	$5,750	0.05 x B
Other	$0	As required
Construction Period	0	Years (n)
Interest Rate	7.0	Percent (i)
Interest during construction (Int.)	$0	DC x i x n
Total Indirect Cost (IC)	**$36,800**	0.32B + Other
Total Capital Investment (TCI) = DC + IC	**$661,337**	1.32B + SP + Bldg + DC

Table 2
Methane Annual Cost Analysis - Certified Low Leaking Valve

Item	Value	Basis
Direct Annual Costs (DC)		
Operating Labor		
Inspection labor req.	$42,800	5 min to inspect a valve monthly @ $50 /hr
Supervisor	$6,420	15% Operating labor
Cost for inspection infrastructure	$2,500	lifts and temporary scaffolding
Total Cost ($/yr)	$51,720	
Maintenance		
Valve replacement labor	$0	All valves replaced over 5 years, 10 hr/replacement
Material	$0	$2500 replacement cost/valve
Cost for replacement infrastructure	$0	lifts and temporary scaffolding
Total Cost ($/yr)	$0	
Indirect Annual Costs (IC		
Capital Recovery	$161,294	CRF x TCI (5 yr life, 7.0% interest
Total Indirect Costs ($/yr)	$161,294	
Total Annualized Costs (TAC) ($)	**$213,014**	
Total Pollutant Controlled (ton/yr) Methane	36.3	80% reduction
COST EFFECTIVENESS $/ton	**$5,874**	$/ton Methane
	$234.95	$/ton CO2e

71.33	inspection hours/month
$50	labor cost/hr
856	total valve count (NG)
171.20	valve/year replaced with 5 year life
5	year life
2,500	$/valve total for replacements not ne
80%	reduction
10	hr/replace a valve

Capital Recovery Factor

Interest	7.0%
Years	5

CRF = i * (1+i)^n / 1+i)^n - 1

CRF = 0.243890694

100	Low leak valve ppm guarantee
500	Standard valve ppm guarantee

APPENDIX F – Additional Information

Post Application NTEC Response #7

State of Wisconsin
DEPARTMENT OF NATURAL RESOURCES

Information Request

FID/Docket Number: 816127840 Date of Request: February 1, 2019

Requested From: WDNR Response Due: February 14, 2019

Contact Requesting Information: Megan Corrado, Air Management Engineer

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
007	Please propose allowable emission rates (lb/hr) of sulfur oxides for the relevant emissions units so that the department may determine whether or not the proposed project causes or exacerbates an exceedance of the Ambient Air Quality Standards [s. NR 404.04(2), Wis. Adm. Code] or increment [s. NR 404.05, Wis. Adm. Code].

Response:

007 The allowable emission rates of sulfur oxides (lb/hr and tpy) emitted for the relevant emissions units are listed in Table 1 below.

Table 1: SO_2 Emission Rates

Source ID	Source Description	SO_2 (lb/hr)	SO_2 (tpy)
S01_DBNG	Turbine NG DB	6.4	28.2
S01_100NG	Turbine NG 100	5.1	28.2
S01_75NG	Turbine NG 75	4.0	28.2
S01_LWNG	Turbine NG 35	2.4	28.2
S01_SSNG	Turbine NG Starts	5.1	28.2
S01_DBFO	Turbine NG DB/FO	6.1	28.2
S01_100FO	Turbine FO 100	4.6	28.2
S01_75FO	Turbine FO 75	3.6	28.2
S01_LWFO	Turbine FO 46	2.8	28.2
S01_SSFO	Turbine FO Starts	4.6	28.2
S02_AUXB	Auxiliary Boiler	0.06	0.3
S04_DPH1	Natural Gas Heater	5.9E-03	0.03
S05_DPT2	Natural Gas Heater	5.9E-03	0.03

Response by: Minda Nelson, P.E.
Title: Associate Environmental Engineer
Department: Burns & McDonnell
Telephone: (816) 822-4208

List Sources of Information:

____

____

____

Information Request Response

BURNS \ McDONNELL

September 1, 2020

Megan Corrado
Air Management Engineer-Adv
State of Wisconsin Department of Natural Resources
101 S. Webster Street
Madison, WI 53707-7921

Re: Nemadji Trail Energy Center
Primary Site: FID No. 816127840 / Draft Permit 18-MMC-168
Alternate Site: FID No. 816121350 / Draft Permit 18-MMC-169
Air Pollution Control Construction Permit Request for Additional Information

Dear Ms. Corrado:

On behalf of South Shore Energy and Dairyland Power Cooperative ("Applicants," collectively), Burns & McDonnell Engineering Company hereby submits its response to the request for additional information for permits 18-MMC-168 and 18-MMC-169.

This response addresses WDNR's request for information confirming that the circuit breakers selected are consistent with the best that is presently available and are 'state of the art' and addresses why a 0.1% leakage rate is not achievable.

Circuit Breaker Performance Details

The below information presents data that supports the installation of three 345-kilovolt (kV) and two 19 kV low-side generator enclosed pressure SF_6 circuit breakers with a guaranteed loss rate of 0.5% by weight or less per year.

1) Circuit Breaker Industry Requirements

The current industry standard requirements of Institute of Electrical and Electronics Engineers (IEEE) is 0.5%. The requirements are listed in IEEE C37.122.3 "IEEE Guide for Sulphur Hexafluoride (SF_6) Gas Handling for High-Voltage Equipment."

> IEEE C37.122.3-2011, Part 4.3.2
> *4.3.2 Closed-pressure systems*
> *In closed-pressure systems, a volume is replenished only periodically by manual connection to an external gas source. High-voltage (above 72.5 kV) SF_6 single-pressure circuit breakers are examples of closed-pressure systems.*
> *It is recommended that:*
> – *The leakage rate be kept lower than 0.5% per annum (p.a.) per gas compartment.*
> – *When SF_6 conditions are checked, that gas be recaptured from analysis equipment.*
> – *Appropriate record-keeping procedures are used.*

9400 Ward Parkway \ Kansas City, MO 64114
O 816-333-9400 \ **F** 816-333-3690 \ burnsmcd.com

A leakage rate of 0.5% listed in the permit is in compliance with the IEEE industry standards.

2) Manufacturer Data
The contacted manufacturers indicated their lab tests demonstrated leakage rates below 0.1% per year. The manufacturers will guarantee this maximum leakage rate only during the warranty period of between 2 to 4 years, depending on the manufacturer.

This demonstrates that the best breakers presently available and ‘state-of-the-art’ breakers will be installed for the project and the installed breakers will meet permit conditions I.C.1.a.(1)(a) and I.C.1.c.(1)(b).

> *I.C.1.a.(1)(a) Circuit breakers containing SF_6 shall be pressurized and have a manufacturer guaranteed loss rate not to exceed 0.5%, by weight, per year: and*
>
> *I.C.1.c.(1)(b) documentation from the manufacturer demonstrating that the circuit breakers installed are enclosed pressure SF_6 circuit breakers with a guaranteed loss rate of 0.5 percent by weight or less by year,*

3) Leak Rates
EPA performed research on SF_6 leak rates from high voltage circuit breakers (See Attachment 1). The study evaluated a fleet of circuit breakers installed between 1998 and 2002 and found the average leakage range was between 0.2% to 2.5% per year over the study period.

The lower bound is overly optimistic relative to leakage over the life of fleet in that it did not include all leakage actually experienced in the fleet (only leakage that triggered the safety alarm) and further the study only evaluated breakers over a period of 2 to 7 years from initial installation versus a typical 30 year life. Even with these extremely optimistic characteristics, the average fleet leakage was found to be higher than the 0.1% per year levels.

It should also be noted that the upper bound (2.5%) is larger than the IEEC requirements (0.5%). The lower bound (0.2%) is higher than the manufacturer guarantees (0.1%), but lower than the IEEC requirement (0.5%).

While NTEC acknowledges that this study is slightly dated and it is possible that the circuit breakers for the project could perform better than those included in the study, it can also be concluded from the study that breakers leak more as they age. In the study, the 6 year old breakers exhibited more leakage than the younger breakers.

Based on this information, the 0.1% lifetime loss rate is not practical.

4) Measurements
Density analyzers will be used to determine compliance with condition I.C.1.c.(1)(i). Specifications for a density monitor is shown in Attachment 2, which shows an overall density measurement accuracy of 0.6% of its range.

This accuracy is not sufficient to measure the SF_6 gas loss of a single year with a permit limit at the 0.5% leakage loss rate and it would take more than 6 years of leakage for the accuracy of the instruments to measure the loss at a 0.1% level. As such, the instruments would not be suitable to provide an early indication of leaks to allow for preemptive maintenance to prevent exceedance of the permit limits if established at the 0.1% level.

Based on this information a 0.1% leakage loss rate limit is not practical.

5) Lifetime Performance
Manufacturer guarantees generally expire after 2 to 4 years of issuance. Manufacturers expect leakage rates will increase over the lifetime (30+ years) of the circuit breakers as components degrade, necessitating periodic overhauls to attempt to restore leakage levels. However, even with the overhauls, it is uncertain whether the leakage rates could be returned to the 0.1% per year level.

A leakage rate permit condition of 0.1% is not economically feasible as the circuit breakers will need to be overhauled and/or replaced more frequently to meet the permit condition.

Additionally, over the life of the equipment the leakage rate will not consistently meet the time-limited manufacturer guaranteed loss rate of 0.1% by weight per year value within the parameters of the permit condition presented in I.C.1.c.(1)(i).

> *I.C.1.c.(1)(i) an inventory of the initial SF_6 quantity and SF_6 replaced in the breakers each calendar year. The SF_6 replaced is assumed equal to the SF_6 that has lost to demonstrate compliance with I.C.1.a.(1)(a).*

6) Economic
The economic impacts of installing circuit breakers with different loss rates was evaluated. For both the switchyard breakers (345 kV) and generator breakers (19 kV), a 0.1% loss rate is not maintainable over the 30-year life of the breakers. The cost analysis assumes that to meet a 0.1% loss rate, each breaker will need to be replaced every five years and for the 0.5% loss rate case the breakers will be replaced at the end of the 30-year life of the breakers.

Switchyard Breakers Economic Analysis
The initial capital costs associated with the switchyard breakers for both a 0.5% loss rate and a 0.1% loss rate is approximately $250,000. This cost is also the cost to replace the breakers every five years to achieve a 0.1% loss rate. The difference in SF_6 losses from a 0.5% and 0.1% loss rate is 0.04 tons SF_6 over 30 years or 0.0014 tons SF_6 per year. On an annual basis, the 0.5% rate would cost approximately $4,852,000 per ton SF_6 over a 30-year life and the 0.1% rate would cost approximately $145,560,000 per ton SF_6 over a 30-year life.

Generator Breakers Economic Analysis
The initial capital costs associated with the generator breakers for both a 0.5% loss rate and a 0.1% loss rate is approximately $700,000. This cost is also the cost to replace the breakers every five years to achieve a 0.1% loss rate. The difference in SF_6 losses from a 0.5% and 0.1% loss rate is 0.0014 tons SF_6 over 30 years or 0.000046 tons SF_6 per year. On an annual basis, the 0.5% rate would cost approximately $405,797,000 per ton SF_6 over a 30-year life and the 0.1% rate would cost approximately $12,173,913,000 per ton SF_6 over a 30-year life.
The details of the cost analysis is shown in Attachment 3. A 0.1% leakage rate results in costs that are economically infeasible due to the cost to replace the circuit breakers. BACT is a 0.5% leakage rate for the circuit breakers.

Conclusion
Based on the above information the conclusions are as follows:

- The circuit breakers will meet industry requirements (0.5% loss rate)
- The best circuit breakers available and 'State-of-the-art' breakers will be installed (Time-limited manufacturer guaranteed loss rate of 0.1% by weight per year.)
- Based on the EPA study the 0.1% lifetime loss rate is not practical.
- Due to density measurement accuracy limitations a 0.1% loss rate limit is not practical.
- Over the life of the equipment the leakage rate will not consistently meet the time-limited manufacturer guaranteed loss rate of 0.1% by weight per year value within the parameters of the permit condition presented in I.C.1.c.(1)(i).
- A leakage rate of 0.1% is not economically feasible due to the cost to continuously replace the circuit breakers over the plant lifetime.

Please note, a 0.1% leakage rate is unprecedented in WDNR permits and would drastically lower the BACT rate to a level that, as described in this response, is not demonstrated over the long term.

In conclusion, the circuit breakers selected are consistent with the best that is presently available and are 'state of the art' and a 0.1% leakage rate is not achievable.

Please contact me at (816) 822-4208 or email me at mnelson@burnsmcd.com if you have any questions.

Sincerely,

Minda Nelson, P.E.
Associate Environmental Engineer

cc: Tim Barton, Burns & McDonnell
Robynn Andracsek, Burns & McDonnell
Daniel McCourtney, Minnesota Power
Melissa Weglarz, Minnesota Power
Erik Hoven, Dairyland Power Cooperative
Brad Foss, Dairyland Power Cooperative
Josh Skelton, South Shore Energy, LLC

ATTACHMENT 1 – EPA STUDY

SF_6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emissions Source

J. Blackman, *Program Manager, U.S. Environmental Protection Agency,*
M. Averyt, *ICF Consulting,* and Z. Taylor, *ICF Consulting*

***Abstract*—This paper highlights a recent collaborative study between the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems and the electric power industry to investigate SF_6 leak rates from high voltage circuit breakers manufactured and installed between 1998 and 2002. Information from over 2,300 circuit breakers were analyzed to quantify the frequency of leaks and to estimate the weighted average annual leak rate for this population of circuit breakers. The methodology, data, and results of this study are presented.**

***Index Terms*-- SF_6, annual leak rate, greenhouse gas emissions, circuit breaker.**

I. Introduction

SULFUR hexafluoride (SF_6) is a gaseous dielectric used in high voltage electrical equipment as an insulator and/or arc quenching medium. SF_6 is the most potent greenhouse gas with a global warming potential that is 23,900 times greater than that of carbon dioxide (CO_2); it is also very persistent in the atmosphere with a lifetime of 3,200 years [1]. Potential sources of SF_6 emissions occur from: 1) losses through poor gas handling practices during equipment installation, maintenance and decommissioning; and 2) leakage from SF_6-containing equipment. The operation and maintenance of SF_6 gas carts, which are used to remove, store, clean, and re-fill SF_6 gas to high-voltage equipment, are considered a major source of handling-related losses. Equipment leakage, on the other hand, is the result of the deterioration of SF_6-containing equipment fittings and materials with time and use through chemical, hardening, and corrosion effects.

Equipment leakage is one of the two potential sources of SF_6 emissions. Leak detection surveys have noted that approximately 10 percent of circuit breaker populations may leak [2, 3], and of these leaking populations, 15 percent of the breaker leaks were minor, with repairs that could be conducted immediately, while the remaining 85 percent were considered significant and had to be referred to operations for scheduled repairs [3]. In terms of where these leaks typically occur, studies have noted that the majority occurs at gas mechanisms (73 percent), 21 percent from worn or broken bushings, and 6 percent from gas tanks [4]. Typically, such losses can only be mitigated through equipment repair or replacement. As electrical equipment ages and reaches the end of its operational service life, replacement rather than equipment repair may provide the more attractive SF_6 mitigation strategy. Many equipment manufacturers now guarantee minimal to zero leak rates for new equipment. Additionally, industry standards recommend that new equipment be built to low leakage limits [5]. Since there is little published information on new equipment leak rates, in a study initiated in 2004, EPA sought to obtain an improved understanding of average leak rates associated with newly manufactured equipment (i.e., installed between 1998 and 2002).

This paper provides a brief review of the data and results of an equipment study funded by EPA [6]. The remainder of this paper is organized into four sections:

- Section II describes the methodology of the field study, including study scope and data parameters.
- Section III provides a summary of the data compiled from utilities participating in the study.
- Section IV presents the results of the equipment leak rate analyses.
- Section V summarizes the conclusions drawn from the study.

II. Field Study Methodology

Section II defines the scope of the study and describes the data collection and compilation process.

A. Study Scope and Data Parameters

The scope of the study was limited to data from three Partner utilities. Information was requested on high voltage circuit breakers manufactured and installed between 1998 and 2002. SF_6 equipment can take the form of sealed or closed pressure systems. Only closed pressure system breakers were included in the study; circuit breakers that are defined as "sealed-for-life" were not addressed by this study. The period in which equipment leakage was assessed was defined as from 1998 through 2005. For purposes of this study, a circuit breaker was classified as leaking if it had documented "top-ups" of SF_6, which occur after a density alarm is sounded, indicating that 10 percent of the circuit breaker gas volume

J. Blackman is with U.S. EPA, Washington, D.C., USA (e-mail: Blackman.Jerome@epa.gov). M. Averyt and Z. Taylor are with ICF Consulting, Washington, D.C. USA (e-mail: maveryt@icfconsulting.com; ztaylor@icfconsulting.com).

has been emitted.

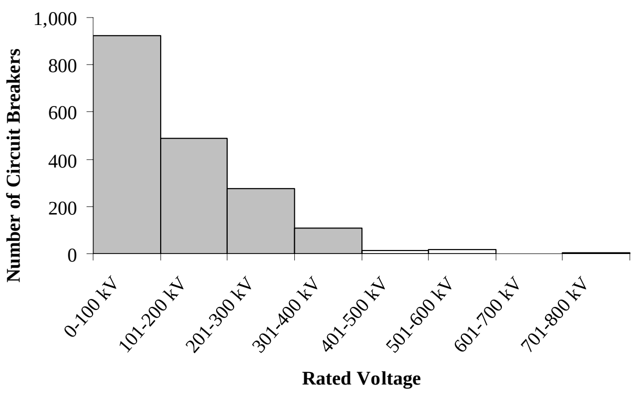
B. Data Collection and Compilation

The data collection was undertaken through a survey form via telephone and email correspondence. The form requested information on the utilities entire inventory of SF_6 breakers, defined by the study scope, including makes, models and installed quantities, number of breaker operations, and for leaking breakers, the quantity of SF_6 gas used during the "top-up" operation.

III. Data Summary

To ensure confidentiality, the names of the utilities involved in the study are not listed. The data provided covered equipment ranging from 33kV to 800kV. In total, information was provided on 2,329 circuit breakers. Figure I illustrates the proportion of circuit breakers size by standard rated voltage. As shown, the majority of the equipment included in the study fell into the range of less than 100 kV. Only 148 breakers were greater 300 kV.

FIGURE I
NUMBER OF CIRCUIT BREAKER BY RATED VOLTAGE



Of the 2,329 circuit breakers, 170 (7.3 percent) were reported as leaking.

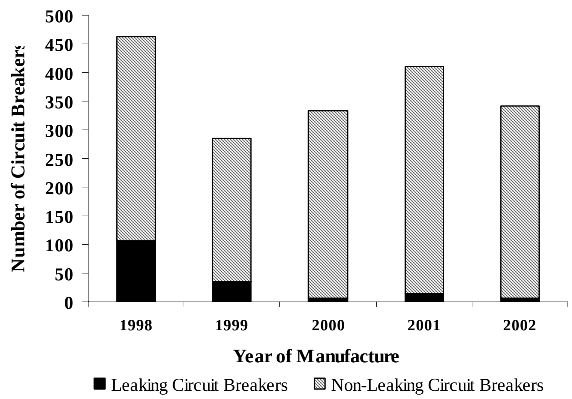
Table I and Figure II present a summary of the number of circuit breakers, leaking and non-leaking, included in the study.

TABLE I
SUMMARY OF LEAKING/NON-LEAKING CIRCUIT BREAKERS

Year of Manufacture	Leaking CB[a]	Non-Leaking CB[b]	Total CB	Leaking CB/Total CB	Leaking as % of Overall Total Leaking
1998	106	357	463	23%	62%
1999	35	250	285	12%	21%
2000	7	326	333	2%	4%
2001	15	396	411	4%	9%
2002	7	334	341	2%	4%
Total	**170**	**1,663**	**1,833[c]**		**100%**

[a]CB – Circuit Breakers
[b]No alarm triggered
[c]Number of circuit breakers does not total 2,329 because year of CB manufacture data are not available for all non-leaking circuit breakers.

FIGURE II
NUMBER OF CIRCUIT BREAKERS BY YEAR OF MANUFACTURE



For the circuit breakers in the data set that were manufactured in 1998, 23 percent were identified as leaking. These circuit breakers account for approximately 62 percent of the total number of leaking breakers. This result is intuitive considering the natural deterioration of seals and equipment over time.

Table II presents emissions data related to the leaking circuit breakers for each year of manufacture. Total emissions of SF_6 are indicated for the leaking circuit breakers manufactured in each year. Total emissions as a percent of total nameplate capacity associated with the leaking circuit breakers are also presented.

TABLE II
SF_6 EMISSIONS FROM LEAKING CIRCUIT BREAKERS

Year Manu-factured	Total Emissions (lbs. SF_6)	No. Leaking CBs	Total Emissions as % of Nameplate Capacity[a]
1998	2,859	106	6%
1999	302	35	0.96%
2000	24	7	0.07%
2001	140	15	0.29%
2002	81	7	0.12%
Total	**3,407**	**170**	

[a]Nameplate capacity of leaking circuit breakers only.

Consistent with the observations in Table I, circuit breakers manufactured in 1998 were also the largest contributors to SF_6 emissions reported in the study. Their emissions as a function of total SF_6-contained in the equipment (nameplate capacity), is approximately 6 percent, significantly larger than the values reported for leaking breakers manufactured in 1999 through 2002.

IV. Leak Rate Results and Analysis

Section IV presents the results of an analysis to define circuit breaker leak rates (as a percent of nameplate capacity) that are representative of the entire reported dataset. These estimates are referred to as the lower and upper bound leak rates, respectively, and are intended to illustrate potential industry trends. The key variables used to perform this analysis are 1) circuit breaker nameplate capacity, 2) total circuit breaker SF_6 leakage (lbs), and 3) the number of years that circuit breaker has been in operation.

Specifically, three leak rates (as a percent of nameplate capacity) were estimated. The first analysis generated a lower bound, or best case scenario, of an average circuit breaker leak rate estimate. The second two analyses both generated upper bound, or worst case scenario circuit breaker leak rate estimates, that are based on different methodologies and assumptions.

A. Lower Bound Weighted-Average Leak Rate

For the lower bound estimate, the weighted-average circuit breaker leak rate is approximately 0.2 percent per year. The lower bound leak rate was calculated by applying the raw reported data to Equation (1) and assuming that 1) through 2005, no additional “top-ups” have occurred after the last reported “top-up” (e.g., if the last reported “top-up was in 2003, it was assumed that no additional leakage occurred through 2005), and 2) for circuit breakers that have not reported any “top-ups” (i.e., they have not reached the 10 percent leakage threshold, and thus have not triggered a notification alarm), their emissions are zero.

This estimate is defined as the weighted average of circuit breaker annual leak rates as a percentage of SF_6 nameplate capacity, across all circuit breakers both leaking and non-leaking. The calculation for the weighted average annual leak rate per nameplate capacity is provided in Equation (1):

$$LC = \frac{\sum \frac{Q_{SF6i}}{Y_i}}{\sum C_i} \qquad (1)$$

Where:
LC = Weighted average annual leak rate per nameplate capacity (percent/year)
Q_{SF6i} = Total mass (i.e., lbs) of SF_6 for all top-up operations since installation for circuit breaker, i
Y_i = Number of years the circuit breaker, i, has been in use
C_i = Individual nameplate capacity for circuit breaker i (lbs SF_6)

B. Upper Bound Weighted-Average Leak Rate – Method 1

For the lower bound estimate, it was assumed that equipment that had not reported “top-ups” were not leaking; however, since “top-ups” are defined by density alarm triggers, it is possible that many more breakers had leaked, but had not reached the 10 percent density alarm leak threshold. To account for potential leakage under the density alarm threshold, an upper bound leak rate estimate was developed based on the following assumptions:

(1) All circuit breakers that have not indicated an alarm trigger leaked slightly less than 10 percent of their capacity between their installation date and 2005. Thus, the 2,159 circuit breakers (93 percent) in the dataset which have no documented “top-ups” (and are assumed for the lower bound to have a leak rate of zero percent) are scaled to assume a leakage rate of 10 percent (this is an asymptotic upper bound).

(2) The second adjustment assumed that for previously identified leaking breakers (those that have reported “top-ups”), an additional 10 percent of capacity (i.e., another “top-up”) occurred between the last documented service call and 2005. For example, a circuit breaker with an annual leak rate of 5 percent whose last reported service call occurred one year before the company data submittal is assumed to have 10 percent additional leakage during that last year.

Based on these assumptions and the application of equation (1) the weighted-average upper bound estimate for circuit breaker leak rate is estimated to be 2.5 percent. This result represents a *worst case* upper bound leak rate.

C. Upper Bound Weighted-Average Leak Rate –Method 2

Since the second assumption listed in the prior section, may overestimate emissions from documented leaking circuit breakers, an additional upper bound estimate was calculated by redefining how additional “top-ups” for these circuit breakers are treated. That is, it was assumed that circuit breakers which are currently leaking will continue to leak at their current rate. That is, if a circuit breaker is calculated to have an existing leak rate of 2 percent per year per nameplate capacity between its installation and last reported top-up date, then it was assumed that this rate continues through the end of the study period. This alternative approach maintains the original assumptions for non-leaking circuit breakers by assuming a leakage of just under 10 percent has occurred since circuit breaker installation.

Based on these assumptions and the application of equation (1), the alternate weighted-average upper bound leak rate estimate is 2.4 percent.

V. CONCLUSION

For the study dataset, the lower and upper bound weighted-average leak rate estimates of 0.2 and 2.5 percent, respectively, represent the best and worst case scenarios for circuit breaker leakage. To put this into some context, NEMA's SF_6 management guidelines state, "…Over a 50 year service life the emission of SF_6 gas due to its use in electrical equipment will not exceed... 5% equipment leakage…" (i.e., 0.1 percent/year) [7]. Also, the IEC standard for new equipment leakage is 0.5 percent per year [5]. While the upper bound is significantly larger than both the NEMA and IEC guidelines, the lower bound leak rate estimate is comparable, and sits between the NEMA and IEC recommendations.

VI. ACKNOWLEDGMENT

The authors would like to acknowledge representatives from Eastern Research Group, Inc (ERG), the Electric Power Research Institute (EPRI), and the electric utilities, and original equipment manufacturers that assisted EPA in undertaking this study.

VII. REFERENCES

[1] IPCC, *Climate Change 1995: The Science of Climate Change.* Intergovernmental Panel on Climate Change; J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds; Cambridge University Press. Cambridge, U.K.

[2] McCreary, J.D., "AEP: A Case Study," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, November 2-3, 2000, San Diego, CA. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/mccrearyppt.pdf

[3] D. Keith, J. Fisher, and T. McRae, "Experience with Infrared Leak Detection on FPL Switchgear," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, November 2-3, 2000, San Diego, CA. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/fischerp.pdf

[4] Salinas, A. and Flores, M., "Southern California Edison: SF_6 Gas Management Program Update," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, December 1-3, 2004, Scottsdale, AZ. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/dec04/Salinas_ok2use.pdf

[5] IEC, International Electrotechnical Commission Standard 62271-1, 2004.

[6] EPA, "High Voltage Circuit Breakers Field Study," prepared by EPRI and the Eastern Research Group, July, 2005.

[7] NEMA, "Management of SF_6 Gas for Use in Electrical Power Equipment," Ad-Hoc Task Group on SF_6, Switchgear Section (8-SG), February, 1998.

VIII. BIOGRAPHY

Jerome Blackman is Program Manager for EPA's SF_6 Emission Reduction Partnership for Electric Power Systems. Mr. Blackman joined EPA in 1995 and has work in several commercial/industrial non-regulatory voluntary pollution prevention programs within the Office of Atmospheric Programs.

Mollie Averyt is an Associate at ICF Consulting. Ms. Averyt specializes in environmental policy analyses related to climate change and ozone depletion issues; and provides support for EPA's SF_6 Emission Reduction Partnership.

Zephyr Taylor is a Research Assistant at ICF Consulting. Mr. Taylor specializes in quantitative modeling and analysis specifically related to climate change issues. Mr. Taylor provides technical support for EPA's SF_6 Emission Reduction Partnership.

ATTACHMENT 2 – DENSITY MONITOR SPECIFICATIONS

Transmitter
For density, temperature, pressureand humidity of SF_6 gas
Model GDHT-20, with MODBUS® output

WIKA data sheet SP 60.14

EAC

for further approvals
see page 3

Applications

- Permanent monitoring of the relevant gas condition parameters in closed tanks
- For internal and external SF_6 gas-insulated equipment

Special features

- High-accuracy sensor technology
- MODBUS® output protocol via RS-485 interface
- Ingress protection IP65
- Very good long-term stability and EMC characteristics
- Compact dimensions

Transmitter, model GDHT-20

Description

The model GDHT-20 transmitter is a multi-sensor system with digital output for the measurands of pressure, temperature and humidity. Based on these measured values, the condition-related data can be determined.

Permanent monitoring
In order to prevent system failures in switchgear and, with that, network outages, the permanent monitoring of the gas density and moisture content is essential.

The GDHT-20 transmitter calculates the current gas density from the pressure and temperature using a complex virial equation in the transmitter's powerful microprocessor. Pressure changes resulting from thermal effects will be compensated by this and will not affect the output value.

In addition, the GDHT-20 transmitter delivers humidity or dew point information, which enables monitoring within the terms of the Cigré directives and IEC standards.

MODBUS® fieldbus
The RS-485 interface communicates using the MODBUS® RTU protocol. The instrument's output parameters and their units can be configured and read according to requirements. The GDHT-20 transmitter can be configured later by the customer for each defined SF_6 gas mixture with N_2 or CF_4.

Signal stability
Due to its high long-term stability, the transmitter is maintenance-free and requires no recalibration.
Due to the hermetically sealed weld seam and a measuring cell design without sealing elements, the permanent sealing of the measuring cell is ensured.

The EMC characteristics fulfil the IEC 61000-4-2 through to IEC 61000-4-6 standards and guarantee an interference-free data output.

Specifications

Measuring ranges

Dew point at ambient pressure:	-50 ... +30 °C
Density:	0 ... 60 g/litre (8.87 bar abs. SF_6 gas at 20 °C)
Temperature:	-40 ... +80 °C
Pressure at 20 °C:	0 ... 8,87 bar abs. SF_6 gas
Pressure:	0 ...16 bar abs.
Burst pressure:	52 bar abs.
Overload safety:	up to 30 bar abs.
Pressure reference:	Absolute

Accuracy [1)]

Specifications only valid for clean gaseous SF_6

Dew point:	±3 K
Density:	±0.60 %, ±0.35 g/litre (-40 ... 80 °C)
Temperature:	±1 K
Pressure:	±0.20 %, ±32 mbar (-40 ... < 0 °C) ±0.06 %, ±10 mbar (0 ... 80 °C)

Long-term stability at reference conditions [2)]

Temperature:	≤ ±0.10 % of span/year
Pressure:	≤ ±0.05 % of span/year
Dew point:	≤ ±0.50 % of span/year

Refresh rate

Density:	20 ms
Temperature:	20 ms
Pressure:	20 ms
Dew point:	2 s (typical), auto-adjustment cycle every 30 min.

Permissible ambient temperature

Selectable versions		
Standard	-40 ... +80 °C -40 ... +176 °F	-40 ... +80 °C -40 ... +176 °F
Option	-60 ... +80 °C -76 ... +176 °F	-60 ... +80 °C -76 ... +176 °F

Power supply U_B^+

DC 17 ... 30 V

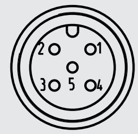
Power consumption

max. 0.5 W (max. 3 W during the heating phase of the humidity sensor)

Electrical connection

Circular connector M12 x 1 (5-pin)
MODBUS® RTU via RS-485 interface

Circular connector M12 x 1 (5-pin)



1	-	-
2	U_B^+	Power supply
3	U_B^-	Ground
4	A	Signal RS-485
5	B	Signal RS-485

1) Following DIN EN 60770-2
2) per IEC 61298-2

Functionality MODBUS®

Mixture ratio of SF_6 to N_2 or CF_4 (default 100 % SF_6 gas)
Customer-specific sensor name

Measured values with alternative units can be retrieved directly in the MODBUS® registers.

- Density: g/litre, kg/m^3
- Temperature: °C, °F, K
- Pressure: mbar, Pa, kPa, MPa, psi, N/cm^2, bar (at 20 °C)
- Humidity: ppmv, ppmw
- Dew point: °C
- Freezing point: °C
- Relative humidity: %

Process connections

Selectable versions
G 1 B, male thread, stainless steel
DN20, female thread
G ½ B, male thread
Malmkvist®
G ⅜ JIS
Flange D40
M10 x 0.5
Via measuring chamber (see page 5)
DN8, female thread
Other connections on request

Case

Stainless steel

Permissible air humidity

≤ 90 % r. h. (non-condensing)

Ingress protection

IP65, only when plugged in and using mating connectors with the corresponding ingress protection

Electrical safety

Protected against reverse polarity, protected against overvoltage

Dimensions

Diameter: 48 mm
Height: 96 mm

Weight

approx. 0.40 kg

EMC tests
For EMC, observe the installation instructions of the operating instructions.

- **Immunity per IEC 61000-4-3:** 30 V/m (80 MHz ... 2.7 GHz)
- **Burst per IEC 61000-4-4:** 4 kV
- **Surge immunity per IEC 61000-4-5:** 1 kV conductor to ground, 1 kV conductor to conductor
- **ESD per IEC 61000-4-2:** 8 kV/15 kV, contact/air
- **High-frequency fields per IEC 61000-4-6:** 3 V

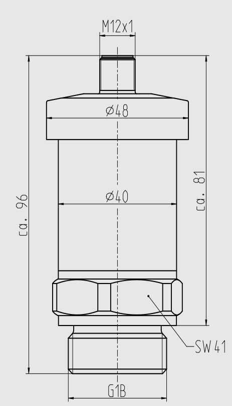
Approvals

Logo	Description	Country
CE	**EU declaration of conformity** ■ EMC directive, EN 61326 emission (group 1, class B) and immunity (industrial application) ■ RoHS directive	European Union
EAC	**EAC** EMC directive	Eurasian Economic Community

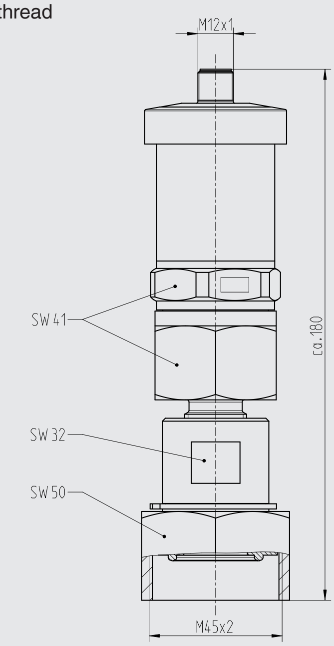
Approvals and certificates, see website

Dimensions in mm

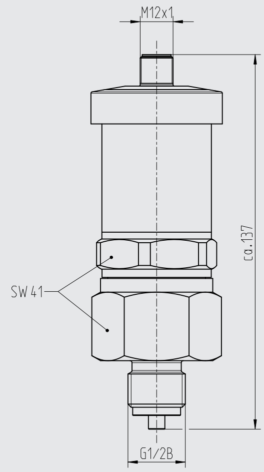
G 1 B, male thread



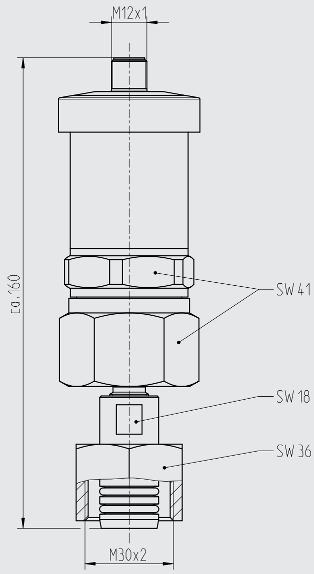
DN20, female thread



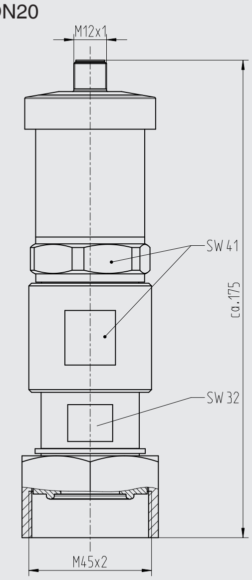
G ½ B, male thread



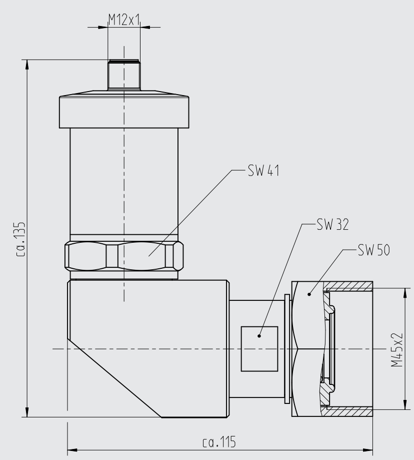
Malmkvist®



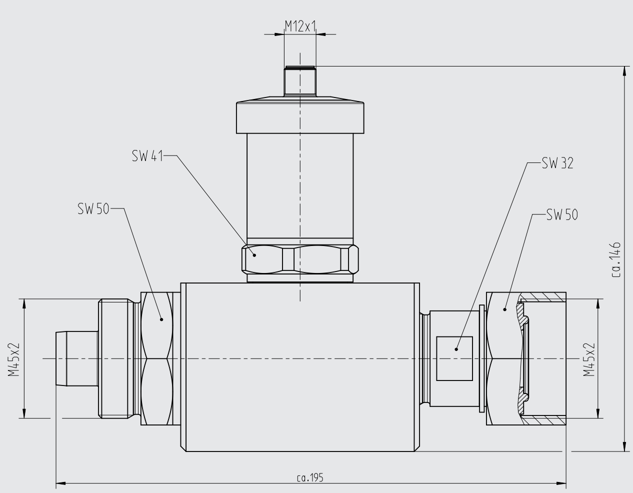
Measuring chamber, DN20



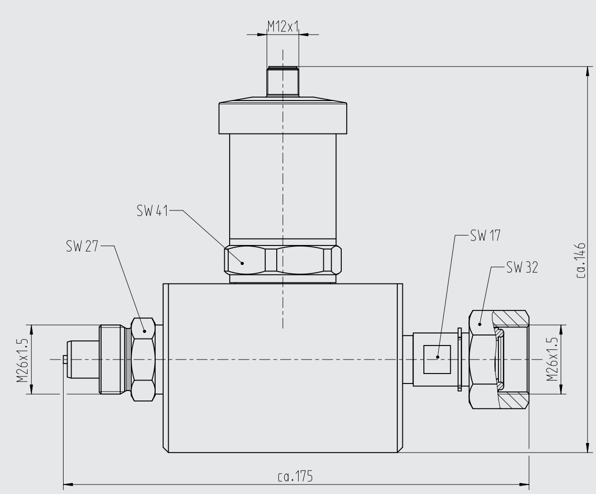
Measuring chamber, DN20, 90° angled



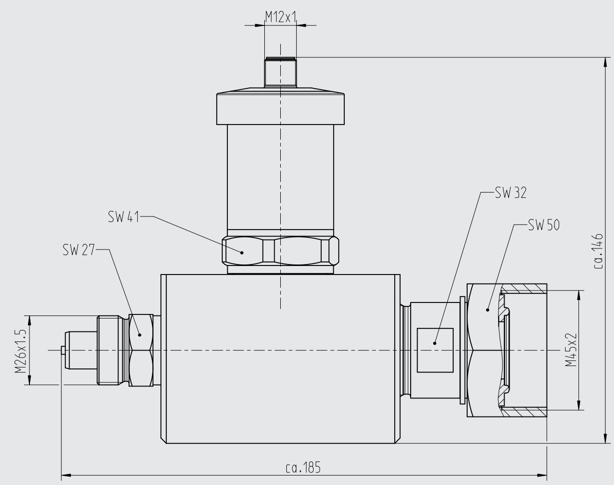
Measuring chamber, DN20 male thread / DN20 female thread



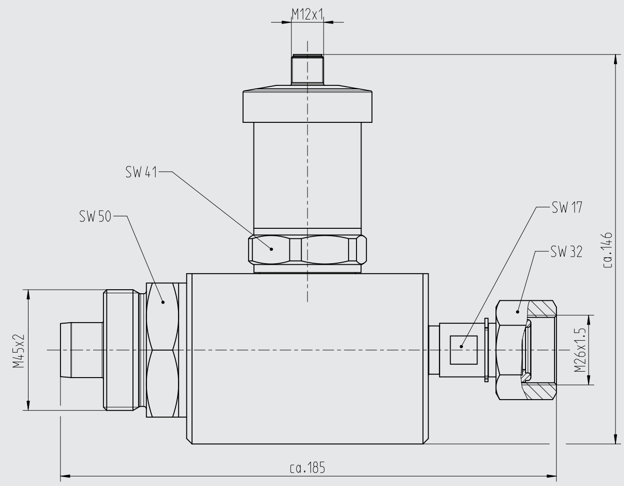
Measuring chamber, DN8 male thread / DN8 female thread



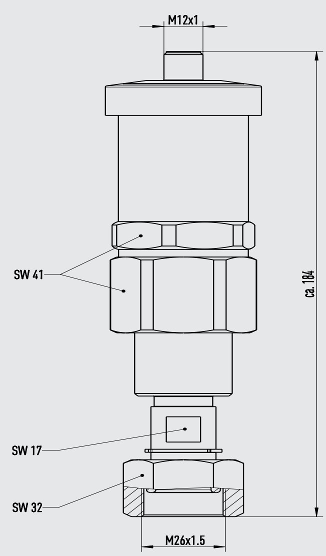
Measuring chamber, DN8 male thread / DN20 female thread



Measuring chamber, DN20 male thread / DN8 female thread



DN8, female thread



Accessories

Designation	Order number
Modbus® startup kit for measured value recording and configuration, consisting of: ■ Power supply unit for transmitter ■ Cable with M12 x 1 connector ■ Interface converter (RS-485 to USB) ■ USB cable type A to type B ■ Modbus® tool software	14075896
WIKAsoft-GD for configuration and testing of the sensor	Free download from: www.wika.com/Download

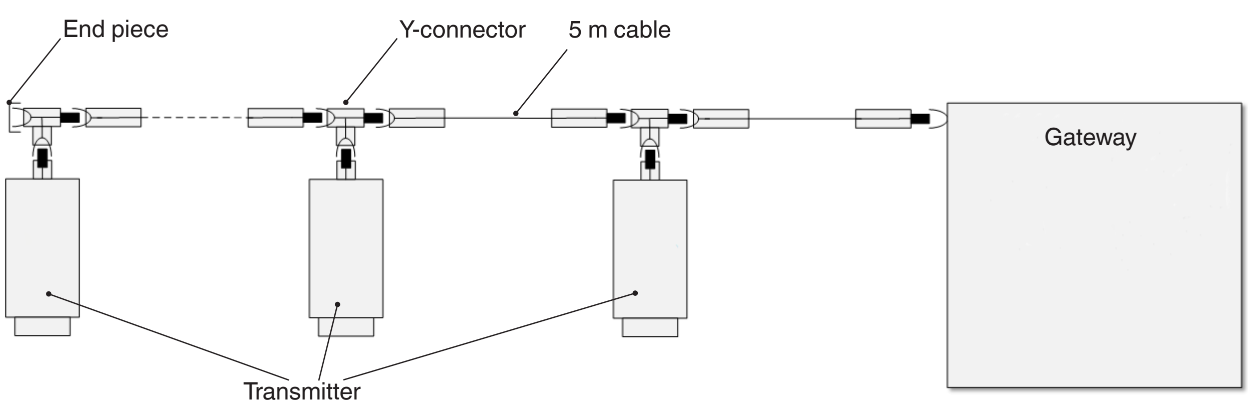
Cable shielded, M12 x 1, AWG20	Order number
Length 1 m	14372501
Length 2 m	14372502
Length 3 m	14372503
Length 4 m	14372504
Length 5 m	14372505
Length 6 m	14372506
Length 7 m	14372507
Length 8 m	14372500
Length 9 m	14372509
Length 10 m	14372510
Length 15 m	14372511
Length 20 m	14372513
Length as required	on request

Conector	Shield	Order number
Y-connector, M12 x 1 (5-pin)	Sensor side unshielded	14294061
T-connector, M12 x 1 (5-pin)	Sensor side unshielded	14294063
Y-connector, M12 x 1 (5-pin)	Sensor side shielded	14271396
T-connector, M12 x 1 (5-pin)	Sensor side shielded	14109450
End piece, M12 x 1	-	14299963

If no cable will be installed between connector and sensor, we recommend using connectors which are unshielded on the sensor side.

Spare parts	Order number
Sealing for process connection G 1 B, male thread, (included in the standard scope of delivery.)	14046738

Installation example



Ordering information

Model / Permissible ambient temperature / Process connection / Accessories

WIKA Alexander Wiegand SE & Co. KG
Alexander-Wiegand-Straße 30
63911 Klingenberg/Germany
Tel. +49 9372 132-0
Fax +49 9372 132-406
info@wika.com
www.wika.de

ATTACHMENT 3 – COST ANALYSIS

Switchyard (345 kV) Breakers

0.5% Loss Rate	
Cost	$ 250,000.00
Replacement interval (yr)	30.00
Replacements over life	1.00
Life (years)	30.00
Annual leak rate	0.5%
SF6 lb/yr	3.44
SF6 lb/30 yr	103.05
SF6 ton/30 yr	0.05
Cost over 30 years/ton SF6	$ 4,852,014
Additional SF6 tons removed over 30 years	0.04
Additional SF6 tons removed per year	0.0014
Global Warming Potential (SF6)	22,800
CO2e lb/30 yr	2,349,540.00
CO2e ton/30 yr	1,174.77
Cost over 30 years/ton CO2e	$ 213
Additional CO2e tons removed over 30 years	939.82
Additional CO2e tons removed per year	31.33

0.1% Loss Rate	
Cost	$ 250,000.00
Replacement interval (yr)	5.00
Replacements over life	6.00
Life years	30.00
annual leak rate (low)	0.1%
SF6 lb/yr	0.69
SF6 lb/30 yr	20.61
SF6 ton/30 yr	0.01
Cost over 30 years/ton SF6	$ 145,560,408
Global Warming Potential (SF6)	22,800
CO2e lb/30 yr	469,908.00
CO2e ton/30 yr	234.95
cost over 30 years/ton CO2e	$ 6,384

Generator (19 kV) Breakers

0.5% Loss Rate	
Cost	$ 700,000.00
Replacement interval (yr)	30.00
Replacements over life	1.00
Life (years)	30.00
Annual leak rate	0.5%
SF6 lb/yr	0.12
SF6 lb/30 yr	3.45
SF6 ton/30 yr	0.0017
Cost over 30 years/ton SF6	$ 405,797,101
Additional SF6 tons removed over 30 years	0.0014
Additional SF6 tons removed per year	0.000046
Global Warming Potential (SF6)	22,800
CO2e lb/30 yr	78,660.00
CO2e ton/30 yr	39.33
Cost over 30 years/ton CO2e	$ 17,798
Additional CO2e tons removed over 30 years	31.46
Additional CO2e tons removed per year	1.05

0.1% Loss Rate	
cost	$ 700,000.00
Replacement interval (yr)	5.00
Replacements over life	6.00
Life years	30.00
Annual leak rate	0.1%
SF6 lb/yr	0.023
SF6 lb/30 yr	0.69
SF6 ton/30 yr	0.0003
Cost over 30 years/ton SF6	$ 12,173,913,043
Global Warming Potential (SF6)	22,800
CO2e lb/30 yr	15,732.00
CO2e ton/30 yr	7.87
Cost over 30 years/ton CO2e	$ 533,944

Auxiliary Boiler Vendor Quote
Post Application NTEC Response #3

From: Andracsek, Robynn
To: Nelson, Minda
Subject: FW: Cost for controls on an aux boiler
Date: Friday, January 11, 2019 10:25:49 AM

Robynn Andracsek 816-822-3596 \ 816-377-1288 randracsek@burnsmcd.com

From: Clayton M. Young <cmyoung@rentechboilers.com>
Sent: Wednesday, October 31, 2018 9:11 AM
To: Andracsek, Robynn <RAndracsek@burnsmcd.com>
Cc: Jason Hayes (jason@jchrep.com) <jason@jchrep.com>
Subject: RE: Cost for controls on an aux boiler

An oxidation catalyst (CO catalyst) would be in the around $75,000 or so. We'd have to build the catalyst housing which adds the to the expense.

Clayton Young
Rentech Boiler Systems, Inc.
Phone: (325) 794-5631

From: Andracsek, Robynn <RAndracsek@burnsmcd.com>
Sent: Wednesday, October 31, 2018 8:29 AM
To: Clayton M. Young <cmyoung@rentechboilers.com>
Cc: Jason Hayes (jason@jchrep.com) <jason@jchrep.com>
Subject: RE: Cost for controls on an aux boiler

Clayton

One more question. If we just put on a oxidation catalyst without an SCR, would it just be $50,000 or would it be more?

Thank you.

Robynn Andracsek 816-822-3596 \ 816-377-1288 randracsek@burnsmcd.com

From: Clayton M. Young <cmyoung@rentechboilers.com>
Sent: Friday, October 19, 2018 4:22 PM
To: Andracsek, Robynn <RAndracsek@burnsmcd.com>
Cc: Jason Hayes (jason@jchrep.com) <jason@jchrep.com>
Subject: RE: Cost for controls on an aux boiler

Individually, the SCR and CO catalyst run about $35,000 (each).

Clayton Young
Rentech Boiler Systems, Inc.
Phone: (325) 794-5631

From: Andracsek, Robynn <RAndracsek@burnsmcd.com>
Sent: Friday, October 19, 2018 1:50 PM
To: Clayton M. Young <cmyoung@rentechboilers.com>
Cc: Jason Hayes (jason@jchrep.com) <jason@jchrep.com>
Subject: RE: Cost for controls on an aux boiler

Clayton

A follow-up question. Do you have a rough cost for SCR and CO catalyst replacement?

Robynn Andracsek 816-822-3596 \ 816-377-1288 randracsek@burnsmcd.com

---

From: Clayton M. Young <cmyoung@rentechboilers.com>
Sent: Friday, October 19, 2018 11:38 AM
To: Andracsek, Robynn <RAndracsek@burnsmcd.com>
Cc: Jason Hayes (jason@jchrep.com) <jason@jchrep.com>
Subject: RE: Cost for controls on an aux boiler

Robynn,

Here are the responses for the additional equipment as requested below. I added a little contingency to the oxidation catalyst number than what I stated on the phone to ensure coverage.

Adder to supply SCR / aqueous ammonia skids & manifold equipment, with a 90% reduction in NOx:

- $350,000.00

Adder to supply CO / Oxidation Catalyst (90% reduction of CO & 50% reduction of VOC's):

- $50,000.00

Thanks and hope you have a great weekend.

Clayton Young
Rentech Boiler Systems, Inc.
Phone: (325) 794-5631

From: Craig Young
Sent: Thursday, October 18, 2018 1:20 PM
To: Clayton M. Young <cmyoung@rentechboilers.com>
Subject: FW: Cost for controls on an aux boiler

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com