APPENDIX A – TITLE V OPERATING PERMIT MODIFICATION WITH STATE CONSTRUCTION APPLICATION AND MODELING REPORT

PERMIT AMENDMENT NO. 4911-303-0039-V-08-1
ISSUANCE DATE: 11/17/2021

GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Air Quality - Part 70 Operating Permit Amendment

Facility Name:	**Washington County Power, LLC**
Facility Address:	**1177 County Line Road**
	Sandersville, Georgia 31082, Washington County
Mailing Address:	**1177 County Line Road**
	Sandersville, Georgia 31082
Parent/Holding Company:	**Washington County Power, LLC**
Facility AIRS Number:	**04-13-303-00039**

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Georgia Rules for Air Quality Control, Chapter 391-3-1, adopted pursuant to and in effect under the Act, the Permittee described above is issued a construction and operating permit for:

Retrofit four simple cycle combustion turbines to fire natural gas or fuel oil.

This Permit Amendment is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Amendment and Permit No. **4911-303-0039-V-08-0**. Unless modified or revoked, this Amendment expires upon issuance of the next Part 70 Permit for this source. This Amendment may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in App No. **TV-547905** dated **February 25, 2021**; any other applications upon which this Amendment or Permit No. **4911-303-0039-V-08-0** are based; supporting data entered therein or attached thereto; or any subsequent submittal or supporting data; or for any alterations affecting the emissions from this source.

This Amendment is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 20 pages.

Richard E. Dunn, Director
Environmental Protection Division

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PART 1.0 FACILITY DESCRIPTION

1.3 Process Description of Modification

Washington County Power (WCP) is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. The project includes the modification of the four existing simple-cycle turbines to allow combustion of either natural gas or fuel oil and the installation of a fuel oil storage tank.

Following the completion of the proposed modification to each combustion turbine (Source Codes T1, T2, T3 and T4), the combustion turbine will be subject to Title 40 CFR Part 60 Subpart KKKK and exempt from Title 40 CFR Part 60 Subpart GG.

PART 2.0 REQUIREMENTS PERTAINING TO THE ENTIRE FACILITY

Modified Condition

2.1 Facility Wide Emission Caps and Operating Limits

2.1.1 The facility shall not discharge, or cause the discharge, into the atmosphere, from the facility, emissions of nitrogen oxides in amounts equal to or in excess of 250 tons during any twelve consecutive months. **This Condition excludes any of the combustion turbines (Source Codes T1, T2, T3 and T4) following its completion of the modification to allow the combustion of fuel oil. This Condition will become void when all four combustion turbines have been modified.**
[Avoidance of 40 CFR 52.21]

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Note: Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

3.1.1 Emission Units- Updated

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	**Description**		**ID No.**	**Description**
T1	Combustion Turbine General Electric 7FA	40 CFR 60 Subpart A **40 CFR 60 Subpart KKKK** 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) **40 CFR 52.21** Acid Rain and CSAPR 40 CFR Part 96	LNB1 **WI1**	Low NOx Burners **Water Injection**
T2	Combustion Turbine General Electric 7FA	40 CFR 60 Subpart A **40 CFR 60 Subpart KKKK** 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) **40 CFR 52.21** Acid Rain and CSAPR 40 CFR Part 96	LNB2 **WI2**	Low NOx Burners **Water Injection**
T3	Combustion Turbine General Electric 7FA	40 CFR 60 Subpart A **40 CFR 60 Subpart KKKK** 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) **40 CFR 52.21** Acid Rain and CSAPR 40 CFR Part 96	LNB3 **WI3**	Low NOx Burners **Water Injection**
T4	Combustion Turbine General Electric 7FA	40 CFR 60 Subpart A **40 CFR 60 Subpart KKKK** 391-3-1-.02(2)(b) 391-3-1-.02(2)(g) **40 CFR 52.21** Acid Rain and CSAPR 40 CFR Part 96	LNB4 **WI4**	Low NOx Burners **Water Injection**
ST1**	**Fuel Oil Storage Tank Vertical Fixed Roof**	**40 CFR 52.21** **391-3-1-.02(2)(b)**	**N/A**	**N/A**

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards intended as a compliance tool and may not be definitive.
****This was included in attachment B of application. There are no changes to the permit for this addition.**

3.2 Equipment Emission Caps and Operating Limits

Modified Condition

3.2.3 The Permittee shall not fire any fuel other than natural gas in the turbines (Source Codes T1, T2, T3 and T4). **This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow the combustion of fuel oil.**
[Avoidance of 40 CFR 52.21]

New Conditions

3.2.4 The Permittee shall not fire any fuel other than pipeline quality natural gas or ULSD (ultra-low sulfur diesel) fuel oil in the turbines (Source Codes T1, T2, T3 and T4). Ultra-low sulfur fuel oil fired in combustion turbines (Source Codes: T1, T2, T3 and T4) shall not contain more than 0.0015 percent sulfur by weight [equivalent to 15 ppm] and shall meet the specifications for Ultra-Low Sulfur No. 1-D S-15A or Ultra-Low Sulfur No. 2-D S-15A as defined by the American Society for Testing and Materials (ASTM) in ASTM D975 – "Standard Specifications for Diesel Fuel Oils."
[40 CFR 52.21(j)(2), 40 CFR 60.4330(a)(2) (subsumed); and 391-3-1-.02(2)(g)(subsumed)]

3.2.5 The Permittee shall not fire natural gas in the combustion turbines (Source Codes T1, T2, T3 and T4) for more than 12,000 hours during any twelve consecutive month period for the total of the four turbines.
[391-3-1-.03(2)(c) and 40 CFR 52.21]

3.2.6 The Permittee shall not fire ULSD fuel oil in the combustion turbines (Source Codes T1, T2, T3 and T4) for more than 2,000 hours during any twelve consecutive month period for the total of the four turbines.
[391-3-1-.03(2)(c) and 40 CFR 52.21]

3.3 Equipment Federal Rule Standards

Modified Conditions

3.3.1 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR Part 60, in particular Subpart A "General Provisions" and Subpart GG - "Standards of Performance for Stationary Gas Turbines," for the construction and operation of the combustion turbines with Source Codes T1, T2, T3 and T4. **This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow the combustion of fuel oil.**
[40 CFR 60 Subpart A and GG]

3.3.3 The Permittee shall not discharge or cause the discharge into the atmosphere from each combustion turbine, T1, T2, T3 and T4, nitrogen oxides in excess of that allowed by the following equation:
[40 CFR 60.332(a)(1)]

$$STD = 0.0075 \times (14.4/Y) + F$$

where: STD = allowable NO_x emissions (% volume @ 15% O_2, dry)
Y = heat rate in kilojoules per watt hour
F = fuel bound nitrogen allowance

Note: The allowable NOx emission concentration defined by the parameter STD does not have to be corrected to ISO conditions.

This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow the combustion of fuel oil.

3.3.4 The Permittee shall not burn in any combustion turbine, T1, T2, T3 and T4, any fuel which contains sulfur in excess of 0.8 percent weight sulfur. **This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow the combustion of fuel oil.**
[40 CFR 60.333(b) and 391-3-1.02(2)(g)(subsumed)]

New Conditions

3.3.6 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR Part 60 Subpart A, "General Provisions" and 40 CFR Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," for the operation of the modified combustion turbines (Source Codes T1, T2, T3 and T4).
[40 CFR 60 Subpart A and KKKK]

3.3.7 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (Source Codes T1, T2, T3 and T4), any gases which:
[40 CFR 52.21 (j)(2), 40 CFR 60.4320, 40CFR 60.4350(h), 40 CFR 60.4380(b)(3)]

a. Contain nitrogen oxides in excess of 9.0 ppmvd, corrected to 15% oxygen or 32.4 ng/J of useful output (0.26 lb/MWh), when firing natural gas, during any four-hour rolling average period, excluding periods of startup and shutdown; and
[40 CFR 52.21(j)(2)]

b. Contain nitrogen oxides in excess of 42.0 ppmvd, corrected to 15% oxygen or 160 ng/J of useful output (1.3 lb/MWh), when firing fuel oil, during any four-hour rolling average period, excluding periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

c. Contain nitrogen oxides in excess of 152.7 tons during any twelve consecutive month period per turbine when firing fuel oil or natural gas, including periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

d. Contain carbon monoxide in excess of 9.0 ppmvd, corrected to 15% oxygen, when firing natural gas, during any three-hour rolling average period, excluding periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

e. Contain carbon monoxide in excess of 20.0 ppmvd, corrected to 15% oxygen, when firing fuel oil, during any three-hour rolling average period, excluding periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

f. Contain carbon monoxide in excess of 70.9 tons during any twelve consecutive month period per turbine when firing fuel oil or natural gas, including periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

g. Contain filterable PM and total PM_{10}/$PM_{2.5}$ in excess of 24.2 pounds per hour when firing natural gas.
[40 CFR 52.21(j)(2)]

h. Contain filterable PM and total PM_{10}/$PM_{2.5}$ in excess of 26.8 pounds per hour when firing fuel oil.
[40 CFR 52.21(j)(2)]

i. Contain volatile organic compounds in excess of 2.0 ppmvd, corrected to 15% oxygen, as methane when firing natural gas.
[40 CFR 52.21(j)(2)]

j. Contain volatile organic compounds in excess of 5.0 ppmvd, corrected to 15% oxygen, as methane when firing fuel oil.
[40 CFR 52.21(j)(2)]

k. Contain greenhouse gases as CO_2e in excess of 387,497 tons during any twelve consecutive month period per turbine when firing fuel oil or natural gas, including periods of startup and shutdown.
[40 CFR 52.21(j)(2)]

3.3.8 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall not burn in any modified combustion turbine (Source Codes: T1, T2, T3 and T4), any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.
[40 CFR 60.4330(a)2 and 391-3-1.02(2)(g)(subsumed)]

3.3.9 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall operate as Best Available Control Technology (BACT) for NOx on each modified combustion turbine (Source Codes: T1, T2, T3 and T4) a dry low NOx combustor for natural gas combustion.
[40 CFR 52.21(j)(2)]

3.3.10 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall operate as Best Available Control Technology (BACT) for NOx on each combustion turbine (Source Codes: T1, T2, T3, and T4) a wet injection spray for fuel oil combustion.
[40 CFR 52.21(j)(2)]

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

Modified Condition

4.1.3 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, and 3.4 are as follows:

a. Method 1 shall be used for the determination of sample point locations,

b. Method 2 shall be used for the determination of stack gas flow rate,

c. Method 3 or 3A shall be used for the determination of stack gas molecular weight,

d. Method 3A or 3B shall be used for emission rate correction factor of excess air,

e. Method 4 shall be used for the determination of stack gas moisture,

f. Method 5 and/or 201A in conjunction with Method 202 shall be used for the determination of particulate matter concentration. The minimum sampling time for each run shall be one hour.

g. Method 7E and the procedures contained in Section 2.121 of the above referenced document shall be used for the determination of nitrogen oxides emissions.

h. Method 9 and the procedures of Section 1.3 of the above reference document shall be used for the determination of opacity,

i. Method 20 shall be used for the determination of nitrogen oxides concentration from combustion turbines T1, T2, T3 and T4 for 40 CFR 60 Subpart GG purposes only.

j. Method 10 shall be used for the determination of carbon monoxide concentration. The sampling time for each run shall be one hour.

k. Method 19 shall be used, when applicable, to convert particulate matter, carbon monoxide, volatile organic compounds and nitrogen oxides concentrations (i.e. grains/dscf for PM, ppm for gaseous pollutants), as determined using other methods specified in this section, to emission rates (i.e., lb/mmBtu).

l. Method 25A for the determination of concentrations of volatile organic compounds.

m. ASTM Test Method D129, D1552, D2622 or D4294 shall be used for the determination of fuel sulfur content.

n. ASTM D4057 shall be used for the collection of fuel oil samples.

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

4.2 Specific Testing Requirements

New Conditions

4.2.1 Within 60 days after achieving the maximum production rate at which each combustion turbine (Source Codes: T1, T2, T3 and T4) will be operated, but no later than 180 days after the initial startup of each combustion turbine following the modification to burn fuel oil, the Permittee shall conduct performance tests on each combustion turbine for NOx emissions in accordance with 40 CFR 60.4400 to verify compliance with Conditions 3.3.7.a and 3.3.7.b. If the NOx CEMS installed and certified under 40 CFR 60.4345 is used as the initial compliance method, the initial performance test for each NOx CEMS specified in Permit Condition 5.2.1 for each affected facility must be performed in accordance with 40 CFR 60.4405.
[40 CFR 52.21, 40 CFR 60.8, 40 CFR 60.4400, and 40 CFR 60.4405]

4.2.2 Within 60 days after achieving the maximum production rate at which each combustion turbine (Source Codes: T1, T2, T3 and T4) will be operated, but no later than 180 days after the initial startup of each turbine following the modification to burn fuel oil, the Permittee shall conduct performance tests for VOC, CO and filterable PM and total $PM_{10}/PM_{2.5}$ on each combustion turbine to verify compliance with emission limits in Condition 3.3.7d, e, g, h, i, and j. The performance tests for carbon monoxide and volatile organic compounds shall be conducted concurrently. The Permittee shall conduct separate tests while firing natural gas and fuel oil in each turbine. The Permittee shall furnish to the Division a written report of the results of such performance tests. Subsequent performance test, on each affected facility, shall be conducted no more than 60 months following the previous performance test.
[391-3-1-.02(3), 391-3-1-.03(2)(c) and 40 CFR 52.21]

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

5.2 Specific Monitoring Requirements

Modified Conditions

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i), and 40 CFR 60.13]

a. A Continuous Emissions Monitoring System (CEMS) for the measurement of NOx concentration and diluent concentration (either oxygen or carbon dioxide) of the discharge to the atmosphere from each combustion turbine (Source Codes: T1, T2, T3 and T4). The one-hour average NOx emissions rates shall be recorded in ppm corrected to 15 percent oxygen on a dry basis, and also in pound per million Btu heat input. The diluent concentration shall be expressed in percent. For purposes of this condition, each one-hour average shall be calculated from at least four data points, each representing a different quadrant of the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For hours that quality assurance and maintenance to the CEMS is performed, a valid hour must have at least two valid data points (one in each of two quadrants of the hour). For the purposes of this condition, each clock hour begins a new one-hour period. The quadrants of the hour begin at 0, 15, 30, and 45 minutes past the hour.
[40 CFR 52.21, 40 CFR 60.4335(b)(1), and 40 CFR 60.4340(b)(1)]

5.2.3 The Permittee shall install, calibrate, maintain, and operate monitoring devices for the measurement of the indicated parameters on the following equipment. Data shall be recorded at the frequency specified below. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Demonstrates that the natural gas meets the definition in 40 CFR 60.331(u) using either of the sources of information specified in 40 CFR 60.334(h)(3)(i) or (ii) combustion turbines T1, T2, T3, and T4.

b. Does not claim an allowance for fuel bound nitrogen.

Otherwise, the Permittee shall determine and record the total sulfur and nitrogen content of the natural gas in accordance with 40 CFR 60.334(i).

This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow the combustion of fuel oil.

5.2.5 For each one-hour period of operation of combustion turbines (Source Codes: T1, T2, T3 and T4), the Permittee shall record the one-hour average NOx concentration measured by the CEMS, the percent O_2 and the four-hour rolling average NOx concentration (in ppm, corrected to 15% O_2, dry basis). For the purposes of this Condition and Condition 6.1.7.a.i, ii, and iii, the four-hour rolling average NOx concentration shall be calculated from the four most recent hours of operation. For an hour to be included in the calculation, the one-hour average concentration must be based upon a minimum of 30 minutes of turbine operation and must include a minimum of two data points, with each data point representing a 15-minute period.
[**40 CFR 60.4380**, 391-3-1-.02(6)(b)1, and 40 CFR 70.6(a)(3)(i)]

New Conditions

5.2.6 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Devices to record the accumulation of hours of operation on generator G1, natural gas pre-heaters H1 and H2 and firewater pump P1, which shows all periods of operation of each unit. Data should be recorded monthly.

b. The quantity of natural gas, in cubic feet, burned in each combustion turbine (Source Codes: T1, T2, T3 and T4). Data shall be recorded monthly.
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i), and 40 CFR 52.21]

c. The quantity of ULSD fuel, in gallons, burned in each combustion turbine (Source Codes: T1, T2, T3 and T4). Data shall be recorded monthly.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 70.6]

d. The monthly oil-fired operating time, in hours, for each combustion turbine (Source Codes: T1, T2, T3 and T4) while burning ULSD fuel, shall be measured. Operating hours shall be recorded for hours in startup and shutdown mode and total hours of operation.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

e. The monthly natural gas-fired operating time, in hours, for each combustion turbine (Source Codes: T1, T2, T3 and T4) while burning natural gas, shall be measured. Operating hours shall be recorded for hours in startup and shutdown mode and total hours of operation.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

f. The electrical output of each combustion turbine (Source Codes: T1, T2, T3 and T4) in megawatts for each hour of operation. The one-hour average megawatts shall be recorded hourly.
[40 CFR 60.4335(b)(3)]

5.2.7 The sulfur content of the ultra-low sulfur diesel fuel burned in the combustion turbines (Source Codes: T1, T2, T3 and T4) shall be monitored by verifying that each shipment of such fuel received complies with the specifications for Grade No. 1-D S15 or No. 2-D S15 as defined in ASTM D975 for ultra-low sulfur diesel fuel. Supplier certifications shall contain the name of the supplier and a statement from the supplier indicating the grade of the fuel as defined in ASTM D975.
[40 CFR 60.4360 and 40 CFR 60.4365]

PART 6.0 OTHER RECORD KEEPING AND REPORTING REQUIREMENTS

6.1 General Record Keeping and Reporting Requirements

Modified Condition

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

Modified Condition

i. Any unit operating hour in which the 4-hour rolling average NOx concentration exceeds that allowed by Condition 3.3.3. For the purpose of this condition, a “4-hour rolling average NOx concentration” is the arithmetic average of the average NOx concentration measured by the NOx CEMS for a given hour (corrected to 15 percent O_2) and the three-unit operating hour average NOx concentrations immediately preceding that unit operating hour. For purposes of this condition, a “unit operating hour” is defined in 40 CFR 60.331(s). **This Condition shall no longer apply to a combustion turbine (Source Codes T1, T2, T3 and T4) upon its restart following completion of the modification to allow combustion of fuel oil.**

New Conditions

ii. Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, any unit operating hour in which the 4-hour rolling average NOx concentration exceeds 15 ppmvd, corrected to 15% oxygen while firing natural gas and 42 ppmvd corrected to 15% while firing fuel oil. For the purposes of 40 CFR Part 60, Subpart KKKK, a “4-hour rolling average NOx emission rate” is the arithmetic average of the average NOx emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOx emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOx emission rate is obtained for at least 3 of the 4 hours.
[40 CFR 60.4380 and Table 1 to 40 CFR Subpart KKKK]

iii. Following the completion of the modification to allow the combustion of fuel oil, for turbines operating at less than 75 percent of peak load**,** for each combustion turbine, any unit operating hour in which the 4-hour rolling average NOx concentration exceeds 96 ppmvd, corrected to 15% oxygen while firing natural gas or fuel oil.
[40 CFR 60.4380 and Table 1 to 40 CFR Subpart KKKK]

iv. Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, any time the total potential sulfur emissions of the fuel being burned in the combustion turbines (Source Codes: T1, T2, T3 and T4) exceed 0.060 lb SO_2/MMBtu heat input (equivalent to 20 grains sulfur per 100 scf).
[40 CFR 60.4385 and 40 CFR 60.4330(a)2]

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

Modified Condition

i. Any twelve consecutive month total NOx emissions from T1, T2, T3, T4, G1, H1, H2, and P1 combined, that equals or exceeds 250 tons. **This Condition excludes any of the combustion turbines (Source Codes T1, T2, T3 and T4) following its completion of the modification to allow the combustion of fuel oil. This Condition will become void when all four combustion turbines have been modified.**

New Conditions: The following Conditions 6.1.7b.iii through 6.1.7b.ix will become applicable to a combustion turbine following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine.

iii. Any period of time that the sulfur content of the fuel oil burned in the combustion turbines (Source Codes: T1, T2, T3 and T4) exceeds 0.0015 percent by weight.
[40 CFR 52.21(2)]

iv. Any twelve consecutive month total hours of operation while firing natural gas in the combustion turbines (Source Codes: T1, T2, T3 and T4) that exceeds 12,000 hours for the total of the four combustion turbines.
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

v. Any twelve consecutive month total hours of operation while firing fuel oil in the combustion turbines (Source Codes: T1, T2, T3 and T4) that exceeds 2,000 hours for the total of the four combustion turbines.
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

vi. Any twelve consecutive month period the NOx emission rate from any combustion turbine (Source Codes: T1, T2, T3 and T4) while firing fuel oil or natural gas that exceeds 152.7 tons.
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

vii. Any twelve consecutive month period the CO emission rate from any combustion turbine (Source Codes: T1, T2, T3 and T4) while firing fuel oil or natural gas that exceeds 70.9 tons.
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

viii. Any twelve consecutive month period the CO_2e emission rate from any combustion turbine (Source Codes: T1, T2, T3 and T4) while firing fuel oil or natural gas that exceeds 387,497 tons.
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

ix. Any four-hour average period, excluding periods of startup and shutdown, that the NOx emission rate exceeds 9.0 ppmvd corrected to 15 % oxygen while firing natural gas or 42 ppmvd corrected to 15% oxygen while fire fuel oil from each combustion turbine (Source Codes: T1, T2, T3 and T4).
[40 CFR 52.21(2), 391-3-1.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)].

d. In addition to the excess emissions, exceedances and excursions specified above, the following should also be included with the report required in Condition 6.1.4:

Modified Conditions

iii. Total monthly NOx emissions of the turbines, G1, H1, H2 and P1, combined. **This Condition excludes any of the combustion turbines (Source Codes T1, T2, T3 and T4) following its completion of the modification to allow the combustion of fuel oil. This Condition will become void when all four combustion turbines have been modified.**

iv. Total NOx emissions of the turbines, G1, H1, H2 and P1, combined, during each of the previous twelve consecutive month periods for each calendar month in the quarterly reporting period. **This Condition excludes any of the combustion turbines (Source Codes T1, T2, T3 and T4) following its completion of the modification to allow the combustion of fuel oil. This Condition will become void when all four combustion turbines have been modified.**

6.2 Specific Record Keeping and Reporting Requirements

Modified Conditions

6.2.3 The Permittee shall use the hour meters required by Condition 5.2.2 **or 5.2.6** to determine the monthly hours of operation of each combustion turbine, of generator G1, gas heaters H1 and H2, and of firewater pump P1.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.4 The Permittee shall use the monthly hours of operation data required by Condition 6.2.3 to compute monthly emissions (tons) of nitrogen oxides from generator G1, gas heaters H1 and H2, and firewater pump P1 as follows:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. G1: (9.23 lb NO_x/hr)(hrs of run time per month)/(2000 lb/ton)

b. H1 and H2: (0.71 lb NO_x/hr)(hrs of run time per month)/(2000 lb/ton)

c. P1: (2.40 lb NO_x/hr)(hrs of run time per month)/(2000 lb/ton)

This Condition will no longer apply upon restart of the combustion turbines (Source Codes T1, T2, T3 and T4) following completion of the modification to allow the combustion of fuel oil.

6.2.5 The Permittee shall use the monthly NOx emission data required in Conditions 6.2.3 and 6.2.4 to calculate the combined 12 consecutive month rolling total of NOx emissions from the combustion turbines, the generator, the gas heaters, and the firewater pump for each calendar month. The Permittee shall notify the Division in writing if the combined 12 consecutive month rolling total of NOx emissions from the combustion turbines, the generator, gas heaters, and the firewater pump equals or exceeds 250 tons. This notification shall be postmarked by the fifteenth day of the following month and shall include an explanation of how the Permittee intends to maintain compliance with the emission limit in Condition No. 2.1.1. **This Condition excludes any combustion turbine (Source Codes T1, T2, T3 and T4) following its completion of the modification to allow the combustion of fuel oil. This Condition will become void when all four combustion turbines have been modified.**
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i) and Avoidance of 40 CFR 52.21]

6.2.7 The Permittee shall retain records of the demonstration found in Condition 5.2.3. **This Condition will no longer apply to each of the combustion turbines (Source Codes T1, T2, T3 and T4) upon restart of the combustion turbine following completion of the modification to allow the combustion of fuel oil.**
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.8 The sulfur content of the natural gas burned in combustion turbines (Source Codes: T1, T2, T3 and T4) shall be monitored by the submittal of a semiannual analysis of natural gas by the supplier or a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less.
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i), **40 CFR 60.4365**]

New Conditions

6.2.10 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall use the monthly NOx emission data required in Condition 6.2.2 to calculate and record the twelve consecutive month rolling total of NOx emissions, in tons, from each combustion turbine, (Source Codes: T1, T2, T3 and T4) for each calendar month. A 12 consecutive month rolling total shall be the total for a month in the reporting period plus the totals for the previous eleven consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i)]

6.2.11 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall maintain the following daily records as they relate to the startup and shutdown of each combustion turbine (Source Codes: T1, T2, T3 and T4) while firing natural gas or fuel oil: the type of fuel fired, the type of startup initiated, the minutes attributed to the startup, and the minutes attributed to shutdown. If the turbine was not in operation on any given day, the records shall so note.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.12 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine (Source Codes: T1, T2, T3 and T4), at the end of each month, the Permittee shall calculate the twelve consecutive month natural gas-fired total operating time, which shall be the sum of its monthly natural gas-fired operating time for that month plus its monthly natural gas-fired operating time for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.13 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine (Source Codes: T1, T2, T3 and T4), at the end of each month, the Permittee shall calculate the twelve consecutive month natural gas-fired operating time spent in startup and shutdown mode, which shall be the sum of its monthly natural gas-fired operating time spent in startup and shutdown mode for that month plus its monthly natural gas-fired operating time spent in startup and shutdown mode for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.14 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine (Source Codes: T1, T2, T3 and T4), at the end of each month, the Permittee shall calculate the twelve consecutive month oil-fired operating time, which shall be the sum of its monthly oil-fired operating time for that month plus its monthly oil-fired operating time for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.15 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine (Source Codes: T1, T2, T3 and T4), at the end of each month, the Permittee shall calculate the twelve consecutive month oil-fired operating time spent in startup and shutdown mode, which shall be the sum of its monthly oil-fired operating time spent in startup and shutdown mode for that month plus its monthly oil-fired operating time spent in startup and shutdown mode for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.16 The sulfur content of the ULSD fuel oil burned in combustion turbines (Source Codes: T1, T2, T3 and T4) shall be monitored by the submittal of a semiannual analysis of fuel oil by the supplier or a current, valid purchase contract, tariff sheet or transportation contract for the fuel oil, specifying that the maximum total sulfur content of the fuel is 0.0015 percent sulfur by weight [equivalent to 15 ppm] or less and shall meet the specifications for Ultra-

Low Sulfur No. 1-D S-15A or Ultra-Low Sulfur No. 2-D S-15A as defined by the American Society for Testing and Materials (ASTM) in ASTM D975 – "Standard Specifications for Diesel Fuel Oils."
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i), 40 CFR 60.4365]

6.2.17 The Permittee shall retain records of the quantity of natural gas fuel burned monthly in the combustion turbines (Source Codes: T1, T2, T3 and T4) for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request.
[40 CFR 52.21(2), 391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i)]

6.2.18 The Permittee shall retain records of the quantity of ULSD fuel oil burned monthly in the combustion turbines (Source Codes: T1, T2, T3 and T4) for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request.
[40 CFR 52.21(2), 391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(i)]

6.2.19 Within 180 days of issuance of this permit, the Permittee shall submit to the Division a CO Mass Emissions Monitoring, Record Keeping and Reporting Plan for the combustion turbines (Source Codes: T1, T2, T3 and T4) for approval. The monitoring plan must contain CO emissions monitoring, CO mass emissions calculation methodology (hourly, monthly, and twelve-month rolling total), recordkeeping, and reporting requirements for the combustion turbines when firing ULSD fuel or natural gas, including periods of startup and shutdown.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 70.6(a)(3)(i)]

6.2.20 Following the completion of the modification to allow the combustion of fuel oil, for each combustion turbine, the Permittee shall use the records required by Condition 5.2.2 or 5.2.6 and the emission factors in the tables below to determine and record the monthly mass emission rate, in tons per month, of CO_2e from each combined combustion turbine and duct burner stack specified in Condition 3.3.1. Total GHG emissions in CO_2e is the sum of the product of each GHG and its respective global warming potential (GWP) per 40 CFR Part 98 Subpart A, Table A-1. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[40 CFR 52.21, 391-3-1-.02(6)(b)1, and 40 CFR 70.6(a)(3)(i)]

GHG	Emission Factor (lb/MMBtu)
CO_2	118.86
CH_4	2.20E-03
N_2O	2.20E-04

Pollutant	Global Warming Potential (GWP)
CO_2	1
CH_4	25
N_2O	298

6.2.21 The Permittee shall use the records required by Conditions 6.2.14 and 6.2.17 to determine and record the twelve consecutive month total emission rate, in tons, of CO_2e emissions from each combined combustion turbine and duct burner stack specified in Condition 3.3.1. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous eleven consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[40 CFR 52.21, 391-3-1-.02(6)(b)1, and 40 CFR 70.6(a)(3)(i)]

6.2.22 The Permittee shall furnish the Division written notification of the actual date of initial startup following completion of the modifications to allow the combustion of fuel oil for each affected facility (Source Codes: T1, T2, T3 and T4) within 15 days after such date for each combustion turbine.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.14 Specific Conditions

New Conditions

7.14.1 The Permittee shall construct and operate the modification as defined in Application No. TV-547905 that is subject to Georgia Rule 391-3-1-.02(7) in accordance with the application submitted pursuant to that rule. If the Permittee constructs or operates a source or modification not in accordance with the application submitted pursuant to that rule or with the terms of any approval to construct, the Permittee shall be subject to appropriate enforcement action.
[40 CFR 52.21(r)(1)]

7.14.2 Approval to construct this modification as defined in Application No. TV-547905 shall become invalid if construction is not commenced within 18 months after the issuance date of this Permit, if construction is discontinued for a period of 18 months or more, of if construction is not completed within a reasonable time. The Director may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date. For purposes of this Permit, the definition of "commence" is given in 40 CFR 52.21(b)(9).
[40 CFR 52.21(r)(2)]

Attachments

B. Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups

ATTACHMENT B

NOTE: Attachment B contains information regarding insignificant emission units/activities and groups of generic emission units/activities in existence at the facility at the time of Permit issuance. Future modifications or additions of insignificant emission units/activities and equipment that are part of generic emissions groups may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Mobile Sources	1. Cleaning and sweeping of streets and paved surfaces	0
Combustion Equipment	1. Fire fighting and similar safety equipment used to train fire fighters or other emergency personnel.	0
	2. Small incinerators that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act and are not considered a “designated facility” as specified in 40 CFR 60.32e of the Federal emissions guidelines for Hospital/Medical/Infectious Waste Incinerators, that are operating as follows: i) Less than 8 million BTU/hr heat input, firing types 0, 1, 2, and/or 3 waste.	0
	ii) Less than 8 million BTU/hr heat input with no more than 10% pathological (type 4) waste by weight combined with types 0, 1, 2, and/or 3 waste.	0
	iii) Less than 4 million BTU/hr heat input firing type 4 waste. (Refer to 391-3-1-.03(10)(g)2.(ii) for descriptions of waste types)	0
	3. Open burning in compliance with Georgia Rule 391-3-1-.02 (5).	0
	4. Stationary engines burning: i) Natural gas, LPG, gasoline, dual fuel, or diesel fuel which are used exclusively as emergency generators shall not exceed 500 hours per year or 200 hours per year if subject to Georgia Rule 391-3-1-.02(2)(mmm).7	1
	ii) Natural gas, LPG, and/or diesel fueled generators used for emergency, peaking, and/or standby power generation, where the combined peaking and standby power generation do not exceed 200 hours per year.	0
	iii) Natural gas, LPG, and/or diesel fuel used for other purposes, provided that the output of each engine does not exceed 400 horsepower and that no individual engine operates for more than 2,000 hours per year.	1
	iv) Gasoline used for other purposes, provided that the output of each engine does not exceed 100 horsepower and that no individual engine operates for more than 500 hours per year.	0
Trade Operations	1. Brazing, soldering, and welding equipment, and cutting torches related to manufacturing and construction activities whose emissions of hazardous air pollutants (HAPs) fall below 1,000 pounds per year.	0
Maintenance, Cleaning, and Housekeeping	1. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system (or collector) serving them exclusively.	0
	2. Portable blast-cleaning equipment.	0
	3. Non-Perchloroethylene Dry-cleaning equipment with a capacity of 100 pounds per hour or less of clothes.	0
	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	0
	5. Non-routine clean out of tanks and equipment for the purposes of worker entry or in preparation for maintenance or decommissioning.	0
	6. Devices used exclusively for cleaning metal parts or surfaces by burning off residual amounts of paint, varnish, or other foreign material, provided that such devices are equipped with afterburners.	0
	7. Cleaning operations: Alkaline phosphate cleaners and associated cleaners and burners.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Laboratories and Testing	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	0
	2. Research and development facilities, quality control testing facilities and/or small pilot projects, where combined daily emissions from all operations are not individually major or are support facilities not making significant contributions to the product of a collocated major manufacturing facility.	0
Pollution Control	1. Sanitary waste water collection and treatment systems, except incineration equipment or equipment subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	2. On site soil or groundwater decontamination units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	3. Bioremediation operations units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	4. Landfills that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
Industrial Operations	1. Concrete block and brick plants, concrete products plants, and ready mix concrete plants producing less than 125,000 tons per year.	0
	2. Any of the following processes or process equipment which are electrically heated or which fire natural gas, LPG or distillate fuel oil at a maximum total heat input rate of not more than 5 million BTU's per hour: i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.	0
	ii) Porcelain enameling furnaces or porcelain enameling drying ovens.	0
	iii) Kilns for firing ceramic ware.	0
	iv) Crucible furnaces, pot furnaces, or induction melting and holding furnaces with a capacity of 1,000 pounds or less each, in which sweating or distilling is not conducted and in which fluxing is not conducted utilizing free chlorine, chloride or fluoride derivatives, or ammonium compounds.	0
	v) Bakery ovens and confection cookers.	0
	vi) Feed mill ovens.	0
	vii) Surface coating drying ovens	0
	3. Carving, cutting, routing, turning, drilling, machining, sawing, surface grinding, sanding, planing, buffing, shot blasting, shot peening, or polishing; ceramics, glass, leather, metals, plastics, rubber, concrete, paper stock or wood, also including roll grinding and ground wood pulping stone sharpening, provided that: i) Activity is performed indoors; & ii) No significant fugitive particulate emissions enter the environment; & iii) No visible emissions enter the outdoor atmosphere.	0
	4. Photographic process equipment by which an image is reproduced upon material sensitized to radiant energy (e.g., blueprint activity, photographic developing and microfiche).	0
	5. Grain, food, or mineral extrusion processes	0
	6. Equipment used exclusively for sintering of glass or metals, but not including equipment used for sintering metal-bearing ores, metal scale, clay, fly ash, or metal compounds.	0
	7. Equipment for the mining and screening of uncrushed native sand and gravel.	0
	8. Ozonization process or process equipment.	0
	9. Electrostatic powder coating booths with an appropriately designed and operated particulate control system.	0
	10. Activities involving the application of hot melt adhesives where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	11. Equipment used exclusively for the mixing and blending water-based adhesives and coatings at ambient temperatures.	0
	12. Equipment used for compression, molding and injection of plastics where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	13. Ultraviolet curing processes where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	**4**
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	0
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	0
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	0

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity

ATTACHMENT B (continued)

GENERIC EMISSION GROUPS

Emission units/activities appearing in the following table are subject only to one or more of Georgia Rules 391-3-1-.02 (2) (b), (e) &/or (n). Potential emissions of particulate matter, from these sources based on TSP, are less than 25 tons per year per process line or unit in each group. Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Emissions Units / Activities	Number of Units (if appropriate)	Applicable Rules		
		Opacity Rule (b)	PM from Mfg Process Rule (e)	Fugitive Dust Rule (n)
N/A				

The following table includes groups of fuel burning equipment subject only to Georgia Rules 391-3-1-.02 (2) (b) & (d).Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Fuel Burning Equipment	Number of Units
Fuel burning equipment with a rated heat input capacity of less than 10 million BTU/hr burning only natural gas and/or LPG.	N/A
Fuel burning equipment with a rated heat input capacity of less than 5 million BTU/hr, burning only distillate fuel oil, natural gas and/or LPG.	N/A
Any fuel burning equipment with a rated heat input capacity of 1 million BTU/hr or less.	N/A

PSD PERMIT APPLICATION

Volume I – Construction Permit Application

Fuel Oil Conversion Project

Washington County Power, LLC

Prepared By:

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Date

Project 201101.0039

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1. EXECUTIVE SUMMARY

Washington County Power, LLC ("WCP") owns and operates a natural gas-fired simple-cycle power generation facility northwest of Sandersville, Georgia (the "Facility"). The Facility consists of four General Electric (GE) Frame 7A combustion turbines, with the capacity to generate approximately 680 MW, along with other ancillary facility equipment including two fuel gas heaters, an emergency fire pump engine, and an auxiliary generator engine. This facility currently operates under Permit No. 4911-303-0039-V-08-0, issued January 11, 2021.

The facility is proposing to modify the four existing simple-cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil.

The proposed project will require a Prevention of Significant Deterioration (PSD) permit as a major modification to an existing major source.[1] Projected-related emissions increases are anticipated to exceed the PSD significant emission rate (SER) thresholds for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).[2]

The application package contains the necessary state air construction and operating permit application for the proposed projects, included in two (2) separate application volumes. This Volume I of the application details the required emissions analyses, regulatory review, and control technology analyses. Volume II of the application package includes all the required air quality assessments necessary as part of this PSD permit application.

1.1 Proposed Project Description

WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hours per year (hr/yr) and fuel oil combustion to 2,000 hr/yr.[3] More detail regarding the proposed projects is provided in Section 2 of this report.

1.2 Permitting and Regulatory Requirements

WCP is submitting this construction and operating permit application, in accordance with the PSD permitting requirements, to request authorization to modify and operate the site's simple-cycle combustion turbines. Since WCP is a major source under the PSD permitting program, emission increases from the proposed projects must be evaluated and compared to the SER thresholds for regulated pollutants under the PSD

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[1] The Facility is currently a PSD minor source, with PSD avoidance limitations (e.g. Permit Condition No. 2.1.1) limiting facility wide emissions of NO_X to less than 250 tpy. The facility is not classified as one of the 28 named source categories, and is subject to a 250 tpy PSD major source threshold.

[2] CO_2e is carbon dioxide equivalents calculated as the sum of the six well-mixed GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) with applicable global warming potentials per 40 CFR 98 applied.

[3] Proposed limits based on 3,000 hr/yr natural gas firing per turbine and 500 hr/yr fuel oil combustion per turbine.

program. WCP has evaluated emissions increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, CO_2e, sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and VOC resulting from the proposed project for comparison to their respective PSD SER to determine whether PSD permitting is required, as shown in Table 1-1.[4]

Table 1-1. Proposed Project Emissions Increases

Pollutant	Project Emissions Increases (tpy)	PSD Significant Emission Rate	PSD Triggered? (Yes/No)
Filterable PM	97.11	25	Yes
Total PM_{10}	154.76	15	Yes
Total $PM_{2.5}$	154.76	10	Yes
SO_2	8.86	40	No
NO_X	565.97	40	Yes
VOC	95.21	40	Yes
CO	264.21	100	Yes
CO_2e	1,402,932	75,000	Yes
Lead	0.03	0.60	No
Sulfuric Acid Mist	3.77	7.00	No

Since the combined project emissions increases of filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e exceed their respective SERs, the proposed project is required to undergo PSD review for each of those pollutants. Emission calculations are described in Section 3 of this application, and PSD permitting requirements are detailed in Section 4.1.

WCP is submitting this construction and operating permit application package in accordance with all federal and state requirements. The proposed project will be subject to federal New Source Performance Standards (NSPS) and the Georgia Rules for Air Quality Control (GRAQC). Applicability of these programs is discussed in Section 4 of this application.

1.3 BACT Determination

WCP performed an analysis of Best Available Control Technology (BACT) for each of the PSD-regulated pollutants that exceeded their SERs (filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e), following the “top-down” approach suggested by U.S. EPA. The top-down process begins by identifying all potential control technologies for the pollutant in question and making a determination if those control options are technically feasible for the specific process. The approach then involves ranking all potentially relevant control technologies in descending order of control effectiveness. The most stringent or “top” control option is BACT unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option does not meet the definition of BACT. Where the top option is not determined to be BACT, the next most stringent alternative is evaluated in the same manner. This process continues until

[4] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, lists the lead (Pb) emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed projects were not evaluated.

BACT is selected. Based on the BACT review, WCP proposes the technology and limits presented in Table 1-2 as BACT for the modified and new emission units. The detailed BACT analysis is presented in Section 5 of this application.

Table 1-2. Summary of Proposed BACT Limits

Unit	Pollutant	Fuel	Selected BACT	Emission / Operating Limit	Compliance Method
Each Simple Cycle Combustion Turbine	NO_X	Natural Gas	DLN Combustors and Good Combustion and Operating Practices	9.0 ppmvd at 15% O_2 on a 4-hour rolling average basis	CEM
		Fuel Oil	Water Injection and Good Combustion and Operating Practices	42.0 ppmvd at 15% O_2 on a 4-hour rolling average basis	
		Both	Secondary BACT	152.7 tpy per rolling 12-months per turbine	
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Natural Gas	Good Combustion and Operating Practices and Low Sulfur Fuels	24.2 lb/hr	Performance Test
		ULSD		26.8 lb/hr	
	CO	Natural Gas	Good Combustion and Operating Practices	9.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	Performance Test
		Fuel Oil		20.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	70.9 tpy per rolling 12-months per turbine	
	VOC	Natural Gas	Good Combustion and Operating Practices	2.0 ppmvd at 15% O_2	Performance Test
		Fuel Oil		5.0 ppmvd at 15% O_2	
	GHGs		Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	387,497 tpy CO_2e per rolling 12-months (each CCCT)	Records of Fuel Usage
Fuel Oil Storage Tank	VOC	N/A	Submerged Fill Pipe, Light Colored Paint for Tank Shell, Good Maintenance Practices		N/A

1.4 Application Contents

Volume I of this permit application is organized as follows:

- Section 2 contains a description of the proposed project;
- Section 3 summarizes emissions calculation methodologies and assesses PSD applicability;
- Section 4 details the regulatory applicability analysis for the proposed project;
- Section 5 contains the required BACT assessment;
- Appendix A includes an area map, site plot plan and simplified process flow diagram;
- Appendix B includes detailed emission calculations;
- Appendix C includes the applicable Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database tables;
- Appendix D includes the control costs analyses completed in support of the BACT review;
- Appendix E contains the Georgia Environmental Protection Division (EPD) SIP construction permit application forms; and

2. PROPOSED PROJECT DESCRIPTION

WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hours per year (hr/yr) and fuel oil combustion to 2,000 hr/yr. The proposed fuel oil storage capacity on-site could be as much as a 2.5 million gallon vertical fixed-roof storage tank, with a conservatively estimated fuel oil throughput of 30 million gallons per year. WCP proposes to continue operating the existing Dry Low NO_X burners on the turbines during gas combustion and proposes to install and operate a water-injection system during fuel oil combustion.

As the units are large-frame simple-cycle units, startup and shutdown operations will generally be limited to less than 30 minutes for both gas and oil operations. Therefore, worst-case hourly conditions for these turbines is generally considered to be a full hour at 100% operating load (steady-state). During gas combustion at 100% operating load, the estimated heat input capacity is estimated to be 1,766 Million British Thermal Units per hour (MMBtu/hr) for each turbine, whereas during fuel oil combustion at 100% operating load, the heat input capacity is estimated to be 1,890 MMBtu/hr for each turbine. Collectively, the four turbines will continue to maintain a 680-MW capacity for the site. WCP does not plan to expand overall short-term generating capacity. However, the annual generation (MW-hr) may increase due to both the addition of fuel oil operating capacity and additional run-time capacity on natural gas. This project would also require WCP to add pump skids, tanks, and a raw water storage tank for the purposes of water injection control but should not require the addition or modification of any other emission units on-site.

WCP proposes to begin making investments (i.e., purchasing equipment) as early as September 2021, and proposes to be operational by the end of 2022. Therefore, WCP is submitting this application into EPD's Expedited Permitting Program to ensure that a final permit is obtained by September 2021.

3. EMISSIONS CALCULATION METHODOLOGY

This section addresses the methodology used to quantify the emissions from the proposed projects and assesses federal New Source Review (NSR) permitting applicability. Emissions from the proposed projects will include CO, NO_X, SO_2, VOC, PM, PM_{10}, $PM_{2.5}$, lead (Pb), H_2SO_4, GHG in the form of CO_2e, and hazardous air pollutants (HAP). These emissions occur as a result of natural gas and fuel oil combustion in the combustion turbines. A new storage tank for fuel oil will also emit small quantities of VOC. Detailed emission calculations are presented in Appendix B.

3.1 NSR Permitting Evaluation Methodology

The NSR permitting program generally requires that a source obtain a permit prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. The NSR program is comprised of two elements: nonattainment NSR (NNSR) and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area the facility is located in is classified as “nonattainment” with the National Ambient Air Quality Standards (NAAQS) for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as “attainment” or “unclassifiable” for the NAAQS. The WCP Sandersville facility is located in Washington County, which is presently designated as “attainment” or “unclassifiable” for all criteria pollutants.[5] As such, PSD permitting is potentially applicable to the proposed projects.

As presently permitted, the existing facility is a synthetic minor PSD source. To facilitate fuel oil combustion, removal of conditions that limit fuel combustion to natural gas will be required. Estimated facility-wide potential-to-emit (PTE) following the proposed change indicates the facility will be considered a PSD major source. Accordingly, if the proposed project meets the definition of *major modification,* the full PSD permitting requirements apply.

The following sections discuss the methodology used in the project emissions increase evaluation conducted to assess PSD applicability under the NSR program. For all PSD-regulated pollutants other than CO_2e, PSD permitting is required if the emissions increase of a specific pollutant exceeds that pollutant’s PSD SER. For CO_2e, PSD permitting is only required if the emissions increase exceeds the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant.[6]

3.2 Defining Existing versus New Emission Units

For purposes of calculating project emissions increases, different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the proposed projects are considered new or existing emission units.

40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units, and are incorporated by reference in the GRAQC:

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[5] 40 CFR 81.311

[6] 40 CFR 52.21(b)(49)(iii) as incorporated by reference in the GRAQC

(i) *A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
(ii) *An existing emissions unit is any unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.*

As the combustion turbines at WCP have operated for more than two years, the proposed projects involve physical or operational changes to existing emission units. The proposed fuel oil storage tank will be considered a new emission unit.

3.3 Annual Emission Increase Calculation Methodology

As WCP is classified as a major source for PSD, if the proposed projects meet the definition of a *major modification*, then the full PSD permitting requirements apply. *Major modification* is defined by 40 CFR 52.21(b)(2)(i):

"Major Modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase … of a regulated NSR pollutant … and a significant net emissions increase of that pollutant …

Certain exemptions to the major modification definition exist that, if applicable, means a project does not require an emission increase assessment. The proposed projects do not qualify for any of the established exemptions.

The project emissions have been analyzed using the current NSR Reform methodology to determine if a significant emissions increase will occur. *Net emissions increase* (NEI) is defined by 40 CFR 52.21(b)(3)(i):

"Net Emissions Increase" means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:

(a) The increase in emissions … as calculated pursuant to paragraph (a)(2)(iv) [for existing units, calculated by actual-to-projected actual[7] *<u>or</u> actual-to-potential; for new units, calculated by actual-to-potential]*[8]

(b) Any other increases or decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…

The first step (1) is commonly referred to as the "project emission increases" as it has historically accounted only for emissions related to the proposed project itself. If the emission increases estimated per step (1) exceed the major modification thresholds, then the applicant may move to step (2), commonly referred to

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[7] 40 CFR 52.21(a)(2)(iv)(c), *<u>Actual-to-projected-actual applicability test for projects that only involve existing emissions units</u>*, states: *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the <u>projected actual emissions</u> … and the <u>baseline actual emissions</u> … equals or exceeds the significant amount for that pollutant …*

[8] 40 CFR 52.21(a)(2)(iv)(d), *<u>Actual-to-potential test for projects that only involve construction of new emissions units</u>*, states: *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …*

as the 5-year netting analysis. The netting analysis includes all projects for which emission increases or decreases (e.g., equipment shutdown) occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting is required. WCP has evaluated the project emissions increase for the proposed projects (i.e., Step 1) using the methodologies outlined in the following sections. An evaluation of the net emissions increase (i.e., Step 2) was not conducted as the facility has no other emissions increases or decreases during the contemporaneous period for the proposed projects.

While the prior quotations only reference three components of the NEI calculation (actual, projected actual, and potential emissions), there are actually five calculated components, with the additional components being (1) a subset of the definition for *projected actual* and (2) additional associated emission unit increases:

- Potential emissions
- Baseline actual emissions
- Projected actual emissions
- "Could have accommodated" emissions exclusion (commonly called the demand growth exclusion)
- Additional associated emission unit increases

3.3.1 Potential Emissions

Potential emissions are defined by 40 CFR 52.21(b)(4) where the potential to emit:

> *…means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable…*

3.3.2 Baseline Actual Emissions

Baseline actual emissions are defined in GRAQC 391-3-1-.02(7)(a)2(i)(II):

> *For an existing emission unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Division…*

Critical to the use of a 10-year baseline period is the determination that simple-cycle combustion turbines do not qualify as "electric utility steam generating units." As defined per 52.21(b)(31) and incorporated by reference per GRAQC 391-3-1-.02(7)(a)2, an electric utility steam generating unit:

> *…means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale.*

Simple-cycle combustion turbines do not generate steam, only thermal energy for generation of electric power. Accordingly, simple-cycle combustion turbines are not "electric utility steam generating units", allowing the use of a 10-year baseline period for actual emissions.

Pursuant to GRAQC 391-3-1-.02(7)(a)2(i)(II)IV, when a project involves multiple emission units, only one consecutive 24-month period may be used to determine the baseline actual emissions for all of the emission units to be modified. However, a different consecutive 24-month period can be used for each pollutant.

3.3.3 Projected Actual Emissions

Projected actual emissions are defined by GRAQC 391-3-1-.02(7)(a)2(ii)(I):

> *"Projected actual emissions" means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.*

For units in which the proposed projects would not change the potential to emit or the design capacity, projected actual emissions would be for the following five years after authorization of the proposed projects.

In determining projected actual emissions, following GRAQC 391-3-1-.02(7)(a)2(ii)(II)I, the source:

> *Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan.*

In addition, when calculating projected actual emissions WCP can exclude emissions that could have been accommodated prior to the projects and that are unrelated to the projects, pursuant to GRAQC 391-3-1-.02(7)(a)2(ii)(II)III.

3.3.4 Could Have Accommodated Emissions

An exclusion, per GRAQC 391-3-1-.02(7)(a)2(ii)(II)III, is included in the definition of projected actual emissions and is a value that is subtracted from the projected actual emissions for existing emission units:

> *May exclude, in calculating any increase in emissions that results from the particular project, [1] that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under subparagraph (7)(a)2.(i) of this rule and that is also [2] unrelated to the particular project, including any [3] increased utilization due to product demand growth (the increase in emissions that may be excluded under this subparagraph shall hereinafter be referred to as "demand growth emissions")... [emphasis added, numbers 1, 2, 3 added]*

Thus, projected emissions increases are exempted when (1) a unit could have accommodated the emissions during the baseline 24-month period, (2) the increases do not result from the particular project, and (3) the increases are related to increased product demand. As the proposed project entails the use of a new fuel, potential emission increases from the combustion of fuel oil would result from the proposed project, therefore the emissions cannot be exempted as could have accommodated emissions.

3.3.5 Additional Associated Emission Unit Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases. WCP has accounted for the possibility of associated emission increases from the natural gas preheaters at the facility.

3.4 Net Emission Increase Evaluation

The following sections summarize the methods used to estimate the emissions increases from the proposed project. Detailed emission calculations are presented in Appendix B.

3.4.1 Baseline Actual Emissions

As discussed in Section 3.3.2, the allowable lookback period for baseline actual emissions is 10 years. For the purposes of selecting appropriate baseline actual emissions, WCP has obtained historically monitored monthly emission totals of NO_X as well as historically monitored monthly heat inputs for each simple-cycle combustion turbine during the period of January 2010 through June 2020. For each pollutant which has not been historically monitored, emissions are calculated using the historically monitored monthly heat inputs for each simple-cycle combustion turbine and the emission factors for turbine combustion of natural gas.

The period of June 2010 to May 2012 was selected as the 2-year (consecutive 24-month) baseline period for Filterable PM, Total PM_{10}, Total $PM_{2.5}$, NO_X, VOC, CO, CO_2e, and H_2SO_4. Additionally, a period of August 2011 to July 2013 was selected as the 2-year (consecutive 24-month) baseline period for SO_2. Baseline actual emissions data utilized for the NSR analysis for each simple-cycle combustion turbine can be found in Appendix B.

3.4.2 Project Potential-to-Emit

Project potential emissions for the modified simple-cycle combustion turbines were determined for use in the NSR analysis and are based on a maximum annual operation of 3,000 hours of natural gas-firing and 500 hours of fuel oil-firing for each simple-cycle combustion turbine. The potential emissions for each simple-cycle combustion turbine are determined on a pollutant-by-pollutant basis for the combustion of natural gas and fuel oil. This potential to emit also includes annual tpy emission estimates for NO_X, CO, and VOC considering and inclusive of startup/shutdown activities at the facility. A number of hours were allotted for startup/shutdown activities for each turbine under both natural gas and fuel oil usage. These hourly estimates of startup/shutdown hours were used along with estimates of emissions for the pollutants in question during a startup/shutdown hour to estimate annual emissions. Table 3-1 summarizes the emission factors utilized for estimation of potential emissions from natural gas combustion for the four simple-cycle combustion turbine units. Emission factor references are provided in Appendix B.

Table 3-1. Criteria Pollutant Potential Emission Factors for Simple-Cycle Combustion Turbine Firing of Natural Gas

Pollutant	Turbine System		
	Emission Factor	Unit	Basis
NO_X	9	ppmv at 15% O_2	Proposed BACT Limit
CO	9	ppmv at 15% O_2	Proposed BACT Limit
VOC	2	ppmv at 15% O_2	Proposed BACT Limit
Total PM/PM_{10}/$PM_{2.5}$	0.0137	lb/MMBtu	Equivalent to BACT Limit
SO_2	0.0006	lb/MMBtu	Emission Factor
H_2SO_4	0.0004	lb/MMBtu	Emission Factor

Table 3-2 summarizes the emission factors utilized for estimation of potential emissions from fuel oil combustion for the four simple-cycle combustion turbine units. Emission factor references are provided in Appendix B.

Table 3-2. Criteria Pollutant Potential Emission Factors for Simple-Cycle Combustion Turbine Firing of Fuel Oil

Pollutant	Turbine System		
	Emission Factor	Unit	Basis
NO_X	42	ppmv at 15% O_2	Proposed BACT Limit
CO	20	ppmv at 15% O_2	Proposed BACT Limit
VOC	5	ppmv at 15% O_2	Proposed BACT Limit
Total PM/PM_{10}/$PM_{2.5}$	0.0142	lb/MMBtu	Equivalent to BACT Limit
SO_2	0.0015	lb/MMBtu	Emission Factor
Lead	0.000014	lb/MMBtu	Emission Factor
H_2SO_4	0.0039	lb/MMBtu	Emission Factor

Additionally, GHG emissions from the combustion of natural gas and fuel oil are calculated based on the emission factors for CO_2, CH_4, and N_2O listed in 40 CFR 98 Subpart C, Tables C-1 and C-2. Total GHG in terms of CO_2e is calculated by multiplying each individual GHG emitted by its respective global warming potential from Table 1 to 40 CFR 98 Subpart A.

3.4.3 New Unit Potential Emissions

A new fuel oil storage tank is being proposed for installation. The fuel oil storage tank will have a capacity of 2.5 million gallons and is assumed to operate continuously at 8,760 hours per year. Emissions from the storage tank are estimated using the latest version of Trinity's TankESP Software (TankESP). TankESP is a tank emissions calculation software product suite that uses the emission estimation procedures from Chapter 7 of AP-42 for VOC emissions from storage tanks. Physical data for the fuel oil storage tank and area-specific meteorological data was utilized in the TankESP software to generate an accurate estimate of VOC emissions. For the purposes of estimating potential emissions, it is conservatively assumed that the tank will experience one turnover of fuel oil per month for a total fuel oil throughput of 30 million gallons per year.[9]

3.4.4 Additional Associated Emission Unit Increases

WCP anticipates that each of the two natural gas preheaters at the facility will experience associated emission increases due to additional hours of potential annual operation resulting from the proposed project. To estimate the preheater operational increases associated with this project, WCP analyzed historical annual turbine usage (from 2015 to 2019) relative to the proposed 3,000 hours of annual natural gas combustion per turbine. A ratio of potential to historical turbine natural gas combustion was established and utilized in conjunction with historical annual preheater usage (from 2015 to 2019) to ascertain an estimated increase in annual operation for the preheaters. This analysis resulted in an estimated operational increase of 5,088 hours per year for each natural gas preheater. Please refer to Appendix B for detailed calculations regarding anticipated operational increases for the two natural gas preheaters.

3.4.5 NSR Emissions Increase Summary

Table 3-3 shows the total emissions increase of the proposed project compared to the NSR major modification thresholds. Detailed emission calculations can be found in Appendix B of this application report.

Table 3-3. Project Emissions Increase

Pollutant	Modified Unit Baseline Emissions (tpy)	Modified Unit Projected Actual Emissions	New Unit Potential Emissions (tpy)	Emissions Increase from New & Modified Units (tpy)	Associated Units Emissions Increases (tpy)	Project Emissions Increases (tpy)	PSD Significant Emission Rate	PSD Triggered? (Yes/No)
Filterable PM	11.58	108.59	--	97.02	0.10	97.11	25	Yes
Total PM_{10}	17.63	172.00	--	154.38	0.38	154.76	15	Yes
Total $PM_{2.5}$	17.63	172.00	--	154.38	0.38	154.76	10	Yes
SO_2	0.40	9.19	--	8.79	0.07	8.86	40	No
NO_X	50.00	610.94	--	560.94	5.04	565.97	40	Yes
VOC	8.19	102.45	0.66	94.93	0.28	95.21	40	Yes
CO	23.46	283.44	--	259.98	4.23	264.21	100	Yes
CO_2e	153,070	1,549,985	--	1,396,914	6,017	1,402,932	75,000	Yes
Lead	--	0.03	--	0.03	2.52E-05	0.03	0.60	No
Sulfuric Acid Mist	0.51	4.26	--	3.75	0.02	3.77	7.00	No

3.5 Potential Emissions Estimate

The following sections discuss the methodology used to calculate the potential emissions for each emission unit at the facility. While only the potential annual emissions from each combustion turbine and the new storage tank are necessary for purposes of the NSR project emission increase assessment, the potential emissions of other facility emission units are detailed herein to support the air dispersion modeling analyses detailed in Volume II of this application package.

3.5.1 Natural Gas-Fired Fuel Preheaters

Potential criteria emissions for the natural gas preheaters are conservatively based on 8,760 operational hours per year for each preheater. Emissions of Total $PM/PM_{10}/PM_{2.5}$, NO_X, CO, VOC, and lead are calculated using emission factors from AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-1 and 2 (July

[9] Potential Turbine Fuel Oil Usage (MM gal/yr) = 1,890 (MMBtu/hr/turbine) / 0.139 (MMBtu/gal distillate oil) * 500 (hr/yr) / 10^6 (gal/MM gal) * 4 (turbines) = 27.2 (MM gal/yr)

1998). Emissions of SO_2 and H_2SO_4 are estimated based on the assumption that the sulfur content in natural gas is 0.50 grains per 100 standard cubic feet, 7,000 grains of sulfur per molar pound of sulfur, 100% conversion of fuel sulfur to SO_2, and a 15% oxidation rate of H_2SO_4. GHG emissions from preheater combustion of natural gas are calculated based on the emission factors for CO_2, CH_4, and N_2O listed in 40 CFR 98 Subpart C, Tables C-1 and C-2. Total GHG in terms of CO_2e is calculated by multiplying each individual GHG emitted by its respective global warming potential from Table 1 to 40 CFR 98 Subpart A. See Appendix B for detailed calculations.

3.5.2 Emergency Generators and Fire Pump

Emissions of criteria pollutants from the fire pump engine and auxiliary generator engine are calculated using factors from AP-42 Section 3.3, *Gasoline and Diesel Industrial Engines*, Table 3.3-1 (October 1996). GHG emissions from heater combustion of natural gas are calculated based on the emission factors for CO_2, CH_4, and N_2O listed in 40 CFR 98 Subpart C, Tables C-1 and C-2. Total GHG in terms of CO_2e is calculated by multiplying each individual GHG emitted by its respective global warming potential from Table 1 to 40 CFR 98 Subpart A. Emissions from these engines are calculated assuming 500 hours per year of operation per unit. See Appendix B for detailed calculations.

3.5.3 HAP/TAP Emissions

HAP and toxic air pollutant (TAP) emissions are evaluated from facility sources based on a variety of resources including AP-42 based emission factors. Details regarding the estimation of HAP/TAP emissions, can be found in Appendix B.

3.5.4 Insignificant Emissions Sources

The facility has other small insignificant sources of emissions (e.g. fugitive piping leaks, roads, etc.) at the facility which are not quantified within the potential to emit estimates within this application.

4. REGULATORY APPLICABILITY ANALYSIS

These projects will be subject to certain federal and state air regulations. This section of the application summarizes the air permitting requirements and key air quality regulations that will potentially apply to WCP as a result of these projects. Applicability to NSR, Title V, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), GRAQC, and other potentially applicable regulations to the proposed projects are addressed herein.

4.1 New Source Review Applicability

The NSR permitting program generally requires a source to obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in an emissions increase in excess of certain pollutant threshold levels. EPD administers its major NSR permitting program through GRAQC Rule 391-3-1-.02(7), *Prevention of Significant Deterioration of Air Quality*, which establishes preconstruction, construction and operation requirements for new and modified sources.

The NSR program is comprised of two elements: NNSR and PSD. The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area where the facility is located is classified as “nonattainment” for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as “attainment” or “unclassifiable.” The WCP Sandersville facility is located in Washington County, which has been designated by the U.S. EPA as “attainment” or “unclassifiable” for all criteria pollutants.[10] Therefore, the facility is not subject to NNSR permitting requirements. However, new construction or modifications that result in emissions increases are potentially subject to PSD permitting requirements.

The PSD program only regulates emissions from “major” stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant exceed the major source thresholds. The PSD major source threshold for the Facility is 250 tpy for all regulated pollutants, except GHG.[11, 12] As presently permitted, the existing facility is a synthetic minor PSD source. To facilitate fuel oil combustion, removal of conditions that limit fuel combustion to natural gas will be required. Estimated facility-wide PTE following the proposed change indicates the facility will be considered a PSD major source as potential emissions of at least one regulated pollutant will exceed 250 tpy. For sources which are PSD major for at least one regulated pollutant, the emissions increases for all regulated pollutants resulting from the proposed project must be compared against the PSD SER to determine if the project is subject to PSD review. For CO_2e, PSD permitting is only required if the emissions increase from the proposed project exceeds the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant. The emissions increases from the proposed project for each PSD-regulated pollutant compared to the respective SER are shown in Table 4-1.

[10] 40 CFR 81.311

[11] While fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input are on the “List of 28” named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy, the simple-cycle combustion turbines operated at the Facility do not meet the definition of steam electric plants.

[12] 40 CFR 52.21(b)(49)(iii) and (iv)

Table 4-1. Project Emission Increases Compared to PSD SER

Pollutant	Project Emissions Increases (tpy)	PSD Significant Emission Rate	PSD Triggered? (Yes/No)
Filterable PM	97.11	25	Yes
Total PM_{10}	154.76	15	Yes
Total $PM_{2.5}$	154.76	10	Yes
SO_2	8.86	40	No
NO_X	565.97	40	Yes
VOC	95.21	40	Yes
CO	264.21	100	Yes
CO_2e	1,402,932	75,000	Yes
Lead	0.03	0.60	No
Sulfuric Acid Mist	3.77	7.00	No

As illustrated in Table 4-1, the proposed projects emissions increases exceeds the SER for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e. Accordingly, PSD review is required for these pollutants.

4.2 Title V Operating Permits

40 CFR 70 establishes the federal Title V operating permit program. Georgia has incorporated the provisions of this federal program in its state regulation, Rule 391-3-1-.03(10), *Title V Operating Permits.* This regulation requires that all new and existing Title V major sources of air emissions obtain federally approved state-administered operating permits. A major source as defined under the Title V program is a facility that has the potential to emit either more than 100 tpy for any criteria pollutant, more than 10 tpy for any single HAP, or more than 25 tpy for combined HAP. Potential emissions from WCP exceed the major source threshold for several pollutants. Therefore, the Facility is subject to the Title V program and currently operates under the State issued Part 70 Operating Permit No. 4911-303-0039-V-08-0 issued January 11, 2021.

The proposed projects represent a significant modification of the operating permit. As such, the required Title V modification application elements are included in the Georgia EPD Online System (GEOS) submittal with Application No. 547905.

4.3 New Source Performance Standards

NSPS, located in 40 CFR 60, require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. The following is a summary of applicability and non-applicability determinations for NSPS regulations of relevance to the proposed project. Rules that are specific to certain source categories unrelated to the proposed project are not discussed in this regulatory review.

4.3.1 40 CFR 60 Subpart A – General Provisions

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.3.2 40 CFR 60 Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr

NSPS Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators*, applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971. The rule defines a fossil fuel-fired steam generating unit as:[13]

> *A furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.*

The combustion turbines will not be subject to NSPS Subpart D, because:

- The turbines do not burn fossil fuel for the purpose of producing steam; and
- Units that are subject to NSPS Subpart KKKK are not subject to NSPS Subpart D. Following the proposed modifications, the simple-cycle combustion turbines will be NSPS Subpart KKKK affected facilities.[14]

4.3.3 40 CFR 60 Subpart Da – Electric Utility Steam Generating Units

NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units*, provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification or reconstruction commenced after September 18, 1978.[15] The rule defines an electric utility steam generating unit as:[16]

> …*any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.*

The next critical definition relates to steam generating unit: [17]

> *Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines;*

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[13] 40 CFR 60.41

[14] 40 CFR 60.40(e)

[15] 40 CFR 60.40Da(a)

[16] 40 CFR 60.41Da

[17] 40 CFR 60.41Da

nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

The essential component of the definition is that the unit must be "steam generating". As simple-cycle combustion turbines do not create steam, they do not meet the applicability definition of NSPS Subpart Da and are therefore not subject to NSPS Subpart Da requirements.

4.3.4 40 CFR 60 Subpart Db – Steam Generating Units > 100 MMBtu/hr

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[18] The term "steam generating unit" is defined under this regulation as:[19]

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

As the simple-cycle combustion turbines do not generate steam, they are not subject to requirements per NSPS Subpart Db.

4.3.5 40 CFR 60 Subpart Dc – Small Steam Generating Units

NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989.[20] This subpart applies to steam generating units having a maximum rated heat input capacity of less than or equal to 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr. NSPS Subpart Dc does not apply for similar reasons as detailed for NSPS Subpart Db: combustion turbines are not steam generating units.[21]

4.3.6 40 CFR 60 Subpart K –Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

The requirements of NSPS Subpart K apply to storage vessels for petroleum liquids which have a storage capacity greater than 65,000 gallons and that commenced construction, modification, or reconstruction after

[18] 40 CFR 60.40b(a)

[19] 40 CFR 60.41b

[20] 40 CFR 60.40c(a)

[21] 40 CFR 60.41c

June 11, 1973 and prior to May 19, 1978.[22] The proposed fuel oil storage tank at the Facility has not yet been constructed; therefore, the requirements of NSPS Subpart K do not apply.

4.3.7 40 CFR 60 Subpart Ka – Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

The requirements of NSPS Subpart Ka apply to storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons and that commenced construction, modification, or reconstruction after May 18, 1978 and prior to July 23, 1984.[23] The proposed fuel oil storage tank at the Facility has not yet been constructed; therefore, the requirements of NSPS Subpart Ka do not apply.

4.3.8 40 CFR 60 Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The requirements of NSPS Subpart Kb apply to storage vessels which have a storage capacity greater than 19,813 gallons that store Volatile Organic Liquids (VOL) for which construction, modification, or reconstruction commenced after July 23, 1984.[24] However, per 40 CFR 60.110b(b), NSPS Kb does not apply to storage vessels with a storage capacity greater than 39,890 gallons storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). The proposed fuel oil storage tank at the Facility will have a storage capacity of 2.5 million gallons and will store ultra low-sulfur diesel (ULSD). The maximum true vapor pressure of the ULSD stored in the fuel oil storage tank is far less than the 3.5 kPa threshold; therefore, the requirements of NSPS Kb do not apply.

4.3.9 40 CFR 60 Subpart GG – Stationary Gas Turbines

NSPS Subpart GG, *Standards of Performance for Stationary Gas Turbines*, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[25]

Presently, the combustion turbines are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbines will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG will no longer apply to the WCP combustion turbines following the proposed project.

4.3.10 40 CFR 60 Subpart KKKK – Stationary Combustion Turbines

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18,

[22] 40 CFR 60.110(c)

[23] 40 CFR 60.110a

[24] 40 CFR 60.110b(a)

[25] 40 CFR 60.330(a), (b)

2005.[26] The Facility presently operates four natural gas-fired simple-cycle combustion turbines, each with a heat input capacity exceeding 10 MMBtu/hr. Following the proposed project, the turbines will also be able to combust fuel oil. To determine if the turbines will be subject to NSPS Subpart KKKK following the proposed project, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as:[27]

> *...any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.*

NSPS Subpart KKKK establishes standards for NO_X and SO_2.[28] As the combustion of fuel oil will result in the increase of both pollutants when compared to natural gas combustion, the proposed project qualifies as an NSPS modification, resulting in the Facility's combustion turbines being subject to the requirements of NSPS Subpart KKKK. Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, the existing NSPS Subpart GG requirements will no longer apply.

The following sections detail the applicable requirements as a result of NSPS Subpart KKKK applicability.

4.3.10.1 Emission Limits

Per Table 1 to Subpart KKKK, a modified combustion turbine is limited to NO_X emission limits depending on the type of fuel combusted and the heat input at peak load. For modified combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/MWh useful output. Additionally, for modified combustion turbines firing fuels other than natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 42 ppm at 15% O_2 or 1.3 lb/MWh useful output. Subpart KKKK also includes, for units greater than 30 MW output, a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.[29] Compliance with the NO_X emission limit is determined on a 4-hour rolling average basis.[30] These NSPS Subpart KKKK requirements will replace the NSPS Subpart GG requirements established per Condition 3.3.3 of the existing Title V operating permit.

SO_2 emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input (or 26 ng SO_2/J).[31]

4.3.10.2 Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for

[26] 40 CFR 60.4305(a), (b)

[27] 40 CFR 60.2

[28] 40 CFR 60.4315

[29] Table 1 to Subpart KKKK of Part 60

[30] 40 CFR 60.4350(g), 40 CFR 60.4380(b)(1)

[31] 40 CFR 60.4330(a)(1) or (a)(2), respectively

minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

4.3.10.2.1 NO_X Compliance Demonstration Requirements

The combustion turbine systems currently employ a continuous emission monitoring system (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Per 40 CFR 4340(b)(2)(iv), units operating without water injection that are regulated by 40 CFR Part 75 may rely on the 40 CFR Part 75 Appendix E procedures for documenting ongoing compliance with the NSPS Subpart KKKK NO_X standards with approval from the state. The WCP units operate without water injection during natural gas combustion.

Water injection will be required for fuel oil combustion. 40 CFR 60.4335 establishes NO_X monitoring options for water injection, including use of a CEM, but does not explicitly state that the Part 75 procedures may be relied upon. However, NSPS Subpart KKKK specific requirements for a CEM are detailed in 40 CFR 60.4345, including an option to rely on a CEM installed and certified per 40 CFR Part 75.[32] Therefore, the use of the existing NO_X CEMs meeting the requirements of 40 CFR Part 75 Appendix E should be sufficient for NSPS Subpart KKKK NO_X ongoing compliance monitoring purposes.

Sources demonstrating compliance with the NO_X emission limits via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[33] Initial compliance with the applicable NO_X emission limits will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial RATA to the NO_X emission limit under this subpart.[34]

4.3.10.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by EPD.[35] The total sulfur content of fuel oil combusted in the combustion turbine must be determined by flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.[36]

However, as allowed per 40 CFR 60.4365, WCP elects to opt out of these provisions of the rule by using natural gas and fuel oil which are demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2. This demonstration can be made using one of the following methods:

1. By using valid purchase contracts, tariff sheets, or transportation contracts for the fuel, specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and/or that the maximum total sulfur content for fuel oil is 0.05 weight percent (500 ppmw)

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[32] 40 CFR 60.4345(a), requiring that the relative accuracy test audit of the CEM by performed an a lb/MMBtu basis.

[33] 40 CFR 60.4340(b), 40 CFR 60.4405

[34] 40 CFR 60.4405(c) and (d)

[35] 40 CFR 60.4370(b) and (c)

[36] 40 CFR 60.4370(a), procedures and frequencies per 40 CFR 75, Appendix D, Sections 2.2.3, 2.2.4.1, 2.2.4.2, or 2.2.4.3

or less. These limitations will serve as demonstration that potential emissions will not exceed 0.060 lb/MMBtu.

2. By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

WCP is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines through submittal of a semiannual analysis of the gas by the supplier or a current, valid purchase contract, tariff sheet, or transportation contract for the gaseous fuel, specifying that the maximum sulfur content does not exceed its excursion threshold of 20.0 grains per 100 standard cubic feet.[37] This sulfur content analysis by the supplier satisfies the sulfur content demonstration methodologies for natural gas in 40 CFR 60.4365(a) and (b), respectively. Therefore, continued compliance with this existing permit condition will guarantee compliance with these NSPS KKKK requirements for natural gas combustion.

As a result of this proposed project, all four combustion turbines at the facility will be retrofitted to allow for the combustion of fuel oil. Therefore, in accordance with 40 CFR 60.6365(a) and (b), WCP will now be required to monitor the sulfur content of the fuel oil burned in the combustion turbines through the submittal of a semiannual analysis of the fuel oil by the supplier or a current, valid purchase contract, tariff sheet, or transportation contract for the fuel oil, specifying that the maximum total sulfur content is 0.05 weight percent (500 ppmw) or less.

4.3.10.3 Initial Notification

Per 40 CFR 60.7(a)(4), this permit application serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

4.3.11 40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units* applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 8, 2014 and to any steam generating unit or IGCC modified after June 8, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[38] The existing simple-cycle combustion turbines at the Facility each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, these stationary combustion turbines could potentially be subject to the provisions of NSPS TTTT.

With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after June 18, 2014, not modification. “Reconstruction” is defined as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable standards. The retrofit cost of the proposed project per turbine is $18.5 million. In comparison, the cost of a comparable, entirely new “stationary combustion turbine” capable of combusting both natural gas and fuel oil under NSPS Subpart KKKK is approximately $83 million. Thus, the costs per turbine is far

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[37] Permit No. 4911-303-0039-V-08-0, Condition 6.2.8

[38] 40 CFR 60.5509(a)

less than 50% of comparable, entirely new "stationary combustion turbines" under Subpart KKKK. As the combustion turbines at WCP are existing units and the proposed projects do not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.[39]

4.3.12 Non-Applicability of All Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPS, besides Subpart A, are categorically not applicable to the proposed project.

4.4 National Emission Standards for Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of individual HAP. Facilities with a potential to emit HAP at an amount less than that which is defined as a major source are otherwise considered an area source. The NESHAP allowable emissions limits are most often established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. The NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

The WCP Sandersville facility is presently classified as an area source of HAP emissions and will remain so following the proposed projects. The determination of applicability to NESHAP requirements for the proposed projects is detailed in the following sections. Rules that are specific to certain source categories unrelated to the proposed projects are not discussed in this regulatory review.

4.4.1 40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAP defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP in 40 CFR 63, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

4.4.2 40 CFR 63 Subpart YYYY – Combustion Turbines

NESHAP Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limits for stationary combustion turbines located at major sources of HAP.[40] As an area source of HAP, NESHAP Subpart YYYY does not apply to operations at the Facility.

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[39] 40 CFR 60.5509(a)

[40] 40 CFR 63.6080

4.4.3 40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

NESHAP Subpart DDDDD, *NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Major Source Boiler MACT) regulates boilers and process heaters at major sources of HAP.[41] As an area source of HAP, the Facility is not subject to the Major Source Boiler MACT.

4.4.4 40 CFR 63 Subpart UUUUU – Electric Utility Steam Generating Units

NESHAP Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, applies to electric utility steam generating units (EGUs) that combust coal or oil.[42] Pursuant to 40 CFR 63.9983(a), area source stationary combustion turbines, other than IGCC units, are not subject to Subpart UUUUU. As the WCP Facility is an area source, NESHAP Subpart UUUUU will not apply.

4.4.5 40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources

NESHAP Subpart JJJJJJ, *NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources* (Area Source Boiler MACT) regulates boilers at area sources of HAP.[43] The simple-cycle combustion turbines do not meet the boiler definition pursuant to 40 CFR 63.11237, which also excludes waste heat boilers:

> *Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

Therefore, the requirements of NESHAP Subpart JJJJJJ do not apply to any equipment being modified as part of the proposed project.

4.4.6 Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The applicability of a particular NESHAP to the proposed project can be readily ascertained based on the industrial source category covered. All other NESHAP are categorically not applicable to the proposed projects.

4.5 Compliance Assurance Monitoring

Under 40 CFR 64, Compliance Assurance Monitoring (CAM) facilities are required to prepare and submit monitoring plans for certain emissions units with Title V operating permit applications. The CAM plans are intended to provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-control emissions exceed the major source

[41] 40 CFR 63.7480

[42] 40 CFR 63.9980

[43] 40 CFR 63.11193

thresholds under the Title V operating program. For a subject unit whose post-control emissions also exceed the major source threshold, a CAM plan is required to be submitted with the initial or modification Title V operating permit application. For a subject unit whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the next Title V renewal application.

The simple-cycle combustion turbines at the Facility are presently not subject to CAM requirements as they do not operate control devices. Following the proposed project, each combustion turbine will operate with water injection during periods of fuel oil combustion to reduce NO_X emissions. These units have NO_X CEMS to verify proper operation. Per 40 CFR 64.2(b)(1)(vi), use of a continuous compliance demonstration exempts a unit from the CAM requirements. Therefore, the turbines are not subject to CAM for NO_X purposes.

4.6 Risk Management Plan

Subpart B of 40 CFR 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. The Facility does not exceed the threshold quantity for any of the chemicals and is, therefore, not subject to 40 CFR 68 Subpart B. The Facility is and will continue to be subject to the General Duty Clause under the Clean Air Act Section 112(r)(1), which states:

> *The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.*

4.7 Stratospheric Ozone Protection Regulations

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H of 40 CFR 82 are not applicable to the Facility. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[44] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. WCP will continue to comply with 40 CFR 82 Subpart F.

4.8 Clean Air Markets Regulations

Starting with the Acid Rain Program (ARP) mandated by the 1990 Clean Air Act Amendments, U.S. EPA has developed several market-based “cap and trade” regulatory programs. All market-based regulatory programs are overseen by U.S. EPA’s Clean Air Markets Divisions (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to WCP are:

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[44] 40 CFR 82.150

- Acid Rain Program (ARP) – 1990 - ongoing
- Clean Air Interstate Rule (CAIR) – 2009 - 2014
- Cross-State Air Pollution Rule (CSAPR) – 2015 (ongoing)

4.8.1 Acid Rain Program

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The turbines at the Facility are utility units subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring) but is not subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the turbines do not have the capability to burn coal.

Under 40 CFR 75 of the ARP, WCP is required to operate a NO_X CEMS for each unit to monitor the NO_X emission rate (lb/MMBtu) and to determine SO_2 and CO_2 mass emissions (tons) following the procedures in Appendices D and G, respectively. Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of the monitors within 90 days of commencement of commercial operation, quarterly reports, and an annual compliance certification. The ARP requirements are outlined in Section 7.9 and Attachment D of the Title V permit No. 4911-303-0039-V-08-0. The proposed projects should not alter any applicable requirements of ARP to the WCP operations, with the exception of possible modifications to monitoring methods with use of fuel oil under 40 CFR Part 75. The facility will continue to maintain sufficient allowances under ARP for its operations.

4.8.2 Clean Air Interstate Rule / Cross-State Air Pollution Rule

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NO_X Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions.[45] Initially finalized on July 6, 2011, the CSAPR was scheduled to replace the CAIR on January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") stayed CSAPR, pending a subsequent decision. On August 21, 2012, the D.C. Circuit then vacated CSAPR, remanding it back to EPA for further rulemaking, leaving CAIR in effect until a replacement rule was promulgated.[46] Upon appeal, the U.S. Supreme Court – on April 29, 2014 – upheld the CSAPR, reversing the D.C. Circuit's decision and remanding the case back to that Court for further proceedings consistent with its April 2014 decision. Upon remand, the U.S. government filed a motion with the D.C. Circuit for a lift of the stay of CSAPR on June 26, 2014, and this motion was granted on October 23, 2014. Therefore, the CSAPR has replaced the CAIR. CSAPR Phase 1 implementation began January 1, 2015 for annual programs and May 1, 2015 for the ozone season program. Phase 2 implementation began on January 1, 2017 for annual programs and May 1, 2017 for ozone season programs.

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[45] http://www.epa.gov/airtransport/

[46] EME Homer City Generation, L.P. v. U.S. EPA. U.S. Court of Appeals for the District of Columbia Circuit, No. 11-1302, decided August 21, 2012.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). The CSAPR rule aims to improve air quality by reducing emissions from power plants that contribute to ozone and/or fine particulate pollution in other states. Georgia is subject to CSAPR programs for both fine particles (SO_2 and annual NO_X) and ozone (ozone season NO_X).[47]

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402.[48] In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving, on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. WCP's combustion turbines are affected sources under this regulation, and the proposed project will not alter the applicability of CSAPR to the facility's operations. WCP will continue to maintain sufficient allowances under CSAPR for its operations.

4.9 State Regulatory Requirements

In addition to federal air regulations, GRAQC Chapter 393-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level.[49] This section reviews the source specific requirements for the proposed projects and does not detail generally applicable requirements such as payment of permit fees.

4.9.1 GRAQC 391-3-1-.02(2)(b) – Visible Emissions

Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. Visible emissions testing may be required at the discretion of the Director. The turbines at WCP are subject to this regulation.

The turbines presently fire pipeline-quality natural gas with emissions exhibiting minimal opacity. As the turbines will be modified to combust ULSD fuel oil, it is anticipated that the firing of these relatively clean fuels in conjunction with proper operation ensures compliance with this rule. No applicable requirements per Rule (b) will be altered as a result of the proposed projects.

4.9.2 GRAQC 391-3-1-.02(2)(d) – Fuel-Burning Equipment

Rule (d) limits the PM emissions, visible emissions, and NO_X emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. The GRAQC define "fuel-burning equipment" as follows:[50]

> *"Fuel-burning equipment" means equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or super heating steam, heating air as in warm air furnaces,*

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[47] https://www.epa.gov/airmarkets/map-states-covered-csapr

[48] CSAPR applicability and definitions are repeated in four separate subparts of 40 CFR 97, but each has identical definitions and applicability requirements. Subpart AAAAA (5A), which is for the NO_X Annual program, is used in this discussion.

[49] Current through rules and regulations filed through December 8, 2020. http://rules.sos.ga.gov/gac/391-3-1

[50] GRAQC 391-3-1-.01(cc)

furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls.

The combustion turbines are used for the generation of electric power, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment and are not subject to the requirements of Rule (d).

4.9.3 GRAQC 391-3-1-.02(2)(e) – Particulate Emissions from Manufacturing Processes

Rule (e), commonly known as the process weight rule, establishes PM limits where not elsewhere specified. Combustion turbines are not technically subject to a separate particulate limit rule, and historically have not been regulated by Rule (e). Therefore, the combustion turbines at WCP are not subject to this regulation.

4.9.4 GRAQC 391-3-1-.02(2)(g) – Sulfur Dioxide

Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to fuel-burning sources, not "fuel-burning equipment," this regulation presently applies to the combustion turbines. For the turbines with heat input capacities greater than 100 MMBtu/hr, the fuel sulfur content is limited to not more than 3% by weight.[51] The proposed projects do not alter the applicable requirements of Rule (g), and WCP will continue to comply with Rule (g) via the combustion of pipeline quality natural gas and ULSD. This limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK.

4.9.5 GRAQC 391-3-1-.02(2)(n) – Fugitive Dust

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. WCP will continue to take the appropriate precautions to prevent fugitive dust from becoming airborne for any applicable equipment.

4.9.6 GRAQC 391-3-1-.02(2)(bb) – Petroleum Liquid Storage

Rule (bb) establishes requirements for storage tanks with a capacity greater than 40,000 gallons storing a petroleum liquid with a true vapor pressure greater than 1.52 pounds per square inch absolute (psia). As the ULSD has a true vapor pressure less than 1.52 psia, the new fuel oil storage tank is not subject to the requirements of Rule (bb).

4.9.7 GRAQC 391-3-1-.02(2)(nn) – VOC Emissions from External Floating Roof Tanks

Rule (nn) establishes requirements for external floating roof tanks storing petroleum liquids with a capacity greater than 40,000 gallons. As the proposed fuel oil storage tank is a fixed roof tank and not an external floating roof tank, Rule (nn) will not apply.

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[51] GRAQC 391-3-1-.02(2)(g)2

4.9.8 GRAQC 391-3-1-.02(2)(tt) – VOC Emissions from Major Sources

Rule (tt) limits VOC emissions from facilities that are located in or near the original Atlanta 1-hour ozone nonattainment area. WCP is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[52]

4.9.9 GRAQC 391-3-1-.02(2)(uu) – Visibility Protection

Rule (uu) requires EPD to provide an analysis of a proposed major source or a major modification to an existing source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The visibility-impacting pollutants include NO_X, PM_{10}, SO_2, and H_2SO_4. A screening analysis of federal Class I areas resulted in a Q/d value less than 10. Therefore, a full review of the anticipated impact on visibility was not performed. Further documentation regarding an evaluation of impacts related to these projects on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, is provided in Volume II of this application.

4.9.10 GRAQC 391-3-1-.02(2)(vv) Volatile Organic Liquid Handling and Storage

Georgia Rule (vv) establishes a requirement for use of submerged fill pipes for transfer of volatile organic liquids into storage tanks for specific counties in the state. Washington county is not a listed county, therefore Rule (vv) does not apply to the proposed fuel oil storage tank.[53]

4.9.11 GRAQC 391-3-1-.02(2)(yy) – Nitrogen Oxides from Major Sources

Rule (yy) limits NO_X emissions from facilities that are located in or near the original Atlanta 1-hour ozone nonattainment area. WCP is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[54]

4.9.12 GRAQC 391-3-1-.02(2)(jjj) – NO_X from Electric Utility Steam Generating Units

Rule (jjj) limits NO_X emissions from electric utility steam generating units located in or near the original Atlanta 1-hour ozone nonattainment area. WCP is not located within the geographic area covered by this rule.[55] Therefore, Rule (jjj) is not applicable.

4.9.13 GRAQC 391-3-1-.02(2)(lll) – NO_X from Fuel-Burning Equipment

Rule (lll) limits NO_X emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. WCP is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[56]

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[52] GRAQC 391-3-1-.02(2)(tt)3

[53] GRAQC 391-3-.02(2)(vv)1, 3

[54] GRAQC 391-3-1-.02(2)(yy)2

[55] GRAQC 391-3-1-.02(2)(jjj)8

[56] GRAQC 391-3-1-.02(2)(lll)4

4.9.14 GRAQC 391-3-1-.02(2)(mmm) – NO_X Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity

Rule (mmm) restricts NO_X emissions from small combustion turbines located in or near the Atlanta nonattainment area that are used to generate electricity. WCP is located in Washington County, which is not one of the listed counties regulated under this rule.[57] Therefore, Rule (mmm) does not apply.

4.9.15 GRAQC 391-3-1-.02(2)(nnn) – NO_X Emissions from Large Stationary Gas Turbines

Additional restrictions apply to NO_X emissions from sources located in or near the original Atlanta 1-hour ozone nonattainment area. Specifically, these regulations limit NO_X emissions from stationary gas turbines used to generate electricity. WCP is located in Washington County, which is not one of the listed counties regulated under this rule.[58] Therefore, Rule (nnn) does not apply.

4.9.16 GRAQC 391-3-1-.02(2)(rrr) – NO_X from Small Fuel-Burning Equipment

Rule (rrr) specifies requirements for fuel-burning equipment with capacities of less than 10 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. WCP is not located within the geographic area covered by this rule, and is, therefore, not subject to this regulation.[59]

4.9.17 GRAQC 391-3-1-.02(2)(sss) – Multipollutant Control for Electric Utility Steam Generating Units

Rule (sss) applies to certain large electric utility steam generating units listed within the rule. WCP is not subject to this regulation, because none of its units are listed in the regulation.

4.9.18 GRAQC 391-3-1-.02(2)(uuu) – SO_2 Emissions from Electric Utility Steam Generating Units

Rule (uuu) applies to certain large electric utility steam generating units listed within the rule. WCP is not subject to this regulation, because none of its units are listed in the regulation.

4.9.19 GRAQC 391-3-1-.02(12), (13), and (14) – Cross State Air Pollution Rules (Annual NO_X, Annual SO_2, and Ozone Season NO_X)

These regulations incorporate the Cross State Air Pollution Rule (CSAPR) requirements into the Georgia Rules for Air Quality Control. The regulations provide allocations for Georgia for 2017 and thereafter.

4.9.20 GRAQC 391-3-1-.03(1) – Construction (SIP) Permitting

The proposed projects will require physical construction activities to complete the proposed modifications. Potential emissions associated with the proposed projects are above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i).[60] Further, as discussed in Section 4.1, PSD permitting is

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[57] GRAQC 391-3-1-.02(2)(mmm)6

[58] GRAQC 391-3-1-.02(2)(nnn)6

[59] GRAQC 391-3-1-.02(2)(rrr)2

[60] Based on Georgia EPD guidance, usage of the *de minimis* permitting exemption thresholds must consider actual-to-potential emissions increases, not actual-to-projected actual emissions increases.

required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix D.

4.9.21 GRAQC 391-3-1-.03(10) – Title V Operating Permits

The potential emissions of certain pollutants exceed the major source thresholds established by Georgia's Title V operating permit program. Therefore, WCP is a Title V major source. The facility currently operates under Permit No. 4911-303-0039-V-08-0. This application represents a significant modification to the existing Title V operating permit; accordingly, a GEOS application has been submitted to address Title V related permitting requirements.

4.9.22 Incorporation of Federal Regulations by Reference

The following federal regulations are incorporated in the GRAQC by reference and were addressed previously in the application:

- GRAQC 391-3-1-.02(7) – PSD
- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-.02(10) – Chemical Accident Prevention
- GRAQC 391-3-1-.02(11) – CAM
- GRAQC 391-3-1-.02(12) – CSAPR for Annual NO_X
- GRAQC 391-3-1-.02(13) – CSAPR for Annual SO_2
- GRAQC 391-3-1-.02(14) – CSAPR for Ozone Season NO_X
- GRAQC 391-3-1-.13 – ARP

4.9.23 Non-Applicability of Other GRAQC

A thorough examination of the GRAQC applicability to the proposed projects reveals many GRAQC that do not currently apply, will not apply once the proposed modifications are complete, and do not impose additional requirements on operations. Such GRAQC rules include those specific to a particular type of industrial operation which is not and will not be performed at the Facility or is not impacted by the proposed projects.

5. BACT ANALYSIS

This section discusses the regulatory basis for BACT, the approach used in completing the BACT analyses, and the BACT analyses for the modified turbines and the new storage tank. Based on the BACT review, WCP proposes the technology and limits presented in Table 5-1 as BACT for the modified units.

Table 5-1. Summary of Proposed BACT Limits

Unit	Pollutant	Fuel	Selected BACT	Emission / Operating Limit	Compliance Method
Each Simple Cycle Combustion Turbine	NO_X	Natural Gas	DLN Combustors and Good Combustion and Operating Practices	9.0 ppmvd at 15% O_2 on a 4-hour rolling average basis	CEM
		Fuel Oil	Water Injection and Good Combustion and Operating Practices	42.0 ppmvd at 15% O_2 on a 4-hour rolling average basis	
		Both	Secondary BACT	152.7 tpy per rolling 12-months per turbine	
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	Natural Gas	Good Combustion and Operating Practices and Low Sulfur Fuels	24.2 lb/hr	Performance Test
		ULSD		26.8 lb/hr	
	CO	Natural Gas	Good Combustion and Operating Practices	9.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	Performance Test
		Fuel Oil		20.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	70.9 tpy per rolling 12-months per turbine	
	VOC	Natural Gas	Good Combustion and Operating Practices	2.0 ppmvd at 15% O_2	Performance Test
		Fuel Oil		5.0 ppmvd at 15% O_2	
	GHGs		Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	387,497 tpy CO_2e per rolling 12-months (each CCCT)	Records of Fuel Usage
Fuel Oil Storage Tank	VOC	N/A	Submerged Fill Pipe, Light Colored Paint for Tank Shell, Good Maintenance Practices		N/A

5.1 BACT Requirement

The BACT requirement applies to each new or modified emission unit from which there is an emissions increase of pollutants subject to PSD review. WCP has determined that the proposed project is subject to PSD permitting for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and GHGs, and thus, is subject to BACT for these pollutants. A BACT review is required for each physically modified or newly constructed emission unit. Accordingly, a BACT analysis and detailed discussion of each pollutant subject to PSD permitting is assessed herein for the simple-cycle combustion turbines and the new storage tank. No other units are being physically modified or constructed as part of the proposed project.

5.2 BACT Definition

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21(j)(3)]:

> *(j) Control Technology Review.*
>
> *(3) A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.*

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

> *... an **emissions limitation** (including a visible emission standard) based on the maximum degree of reduction for **each pollutant** subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a **case-by-case basis**, taking into account energy, environmental, and economic impacts and other costs, determines is **achievable** for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. **In no event shall application of best available control technology** result in emissions of any pollutant which would **exceed the emissions allowed by any applicable standard under 40 CFR 60 and 61.***
> [primary BACT definition]
>
> *If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, **a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of best achievable control technology**. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation, and shall provide for compliance by means which achieve equivalent results.*
> [allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

5.2.1 Emission Limitation

...an emissions limitation...

First and foremost, BACT is an emission limit. While BACT is predicated upon the application of technologies to achieve that limit, the final result of BACT is a limit. In general, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/ton, ppm, lb/hr or lb/MMBtu).[61]

[61] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a boiler, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

Furthermore, U.S. EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling averages.[62] It should be noted that the secondary BACT definition per 40 CFR 52.21(b)(12) identifies that in cases where the implementation of an emission limitation is deemed infeasible, a design, equipment, work practice, operational standard or combination of the same may be prescribed as a BACT standard.

5.2.2 Each Pollutant

...each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification...

BACT is analyzed for each pollutant, not a combination of pollutants, even where the technology reduces emissions of more than one pollutant. This is particularly important in performing costs analyses.
While BACT emission limits for PM_{10} and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM or PM_{10} also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable PM_{10} will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed projects is due to NO_X emissions from the turbines. Any secondary PM BACT is effectively addressed by controlling the direct emissions of NO_X, which is addressed through the NOx BACT analysis conducted for the turbines.

For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act is the sum of **six** greenhouse gases and not a single pollutant.[63] Though the primary GHG emissions from natural gas and fuel oil combustion at the combustion turbines are of carbon dioxide (CO_2), GHG BACT is discussed separately for the following additional GHG components: methane (CH_4) and nitrous oxide (N_2O).

5.2.3 Case-by-Case Basis

...a case-by-case basis, taking into account energy, environmental and economic impacts and other costs...

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by U.S. EPA,

> *The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]... The BACT analysis, therefore, involves judgment and balancing.* [64]

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[62] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 46.

[63] The six GHGs are: CO_2, N_2O, CH_4, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

[64] U.S. EPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, pages 41-42.

The case-by-case analysis has also been affirmed by the U.S. EPA Environmental Appeals Board in an order denying review of the PSD permit for the La Paloma Energy Center:[65]

> *As the Board explained in In re Northern Michigan University ("NMU"), the BACT definition requires permit issuers to "proceed[ ] on a case-by-case basis, taking a careful and detailed look, attentive to the technology or methods appropriate for the particular facility, [ ] to seek the result tailor-made for that facility and that pollutant. 14 E.A.D. 283, 291 (EAB 2009)*

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.[66] Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

The five steps in a top-down BACT evaluation can be summarized as follows:

Step 1. Identify all possible control technologies;

Step 2. Eliminate technically infeasible options;

Step 3. Rank the technically feasible control technologies based upon emission reduction potential;

Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations; and

Step 5. Select BACT.

Each of these steps is discussed in detail in Section 5.4. While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 5.2.1, the BACT determination is an emissions limitation and does not require the installation of any specific control device.

5.2.4 Achievable

…based on the maximum degree of reduction …[that Georgia EPD] … *determines is achievable … through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques…*

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life.

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[65] U.S. EPA Environmental Appeals Board decision, In re: La Paloma Energy Center L.L.C. PSD Appeal No. 13-10, decided March 14, 2014. Environmental Administrative Decisions, Volume 16, page 273.

[66] Memo dated December 1, 1987, from J. Craig Potter (EPA Headquarters) to EPA Regional Administrators, titled "Improving New Source Review Implementation."

As discussed by the DC Circuit Court of Appeals,

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[67]

U.S. EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[68]

More recently, this issue was addressed for GHG BACT:[69]

> *Efficiency standards may vary on a case-by-case basis to account for site variability (e.g., altitude) and other factors that could impact process efficiency. In addition, any system will "age" over time and achievable efficiencies may deteriorate. Section 169 contains multiple statutory factors that must be evaluated in determining the "maximum degree of reduction" on which BACT is based. Efficiency improvements in combination with some other control option could be listed as the maximum control, in which case the standard process limits would likely incorporate the effects of the more efficient design and a separate "efficiency" standard would not be necessary. Page B.l6 of the 1990 Draft NSR Workshop Manual notes that "combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated.*[70]

This stance continues to be affirmed by the U.S. EPA Environmental Appeals Board in an order denying review of the PSD permit for the La Paloma Energy Center:[71]

> *"…the Board has recognized that permitting authorities are not always required to impose the highest possible level of control efficiency, but may take case-specific circumstances into consideration in determining what level of control is achievable for a given source. See In re Russell City Energy Ctr., 15 E.A.D. 1, 58-61 (EAB 2010) (rejecting a "bright line" test of requiring the*

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[67] As quoted in Sierra Club v. U.S. EPA (97-1686).

[68] U.S. EPA Environmental Appeals Board decision, In re: Newmont Nevada Energy Investment L.L.C. PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, page 442.

[69] Clean Air Act Advisory Committee (CAAAC) Climate Change Workgroup, *Report of Issue Group 2: Technical Feasibility* https://www.epa.gov/caaac/climate-change-workgroup-reports-and-presentations

[70] https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf

[71] U.S. EPA Environmental Appeals Board decision, In re: La Paloma Energy Center L.L.C. PSD Appeal No. 13-10, decided March 14, 2014. Environmental Administrative Decisions, Volume 16, pages 280-281.

highest or average level of control that another source has achieved), petition denied sub nom. Chabot-Las Positas Cmty, Coll. Dist. V. EPA, 428 F. App'x 219 (9th Cir. 2012); In re Newmont Nev. Energy Inv., LLC, 12 E.A.D. 429, 441 (EAB 2005). ("We recently explained that '[t]he underlying principle of all of these cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology." (citing In re Cardinal FG Co., 12 E.A.D. 153, 170 (EAB 2005)))

Thus, BACT must be set at the lowest feasible emission rate recognizing that the emission unit must be in compliance with that limit for the lifetime of the unit on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[72]

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 5.5).

5.2.5 Floor

Emissions [shall not] exceed the emissions allowed by any applicable standard under 40 CFR 60 and 61.

The least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61 and 63).[73] State SIP limitations must also be considered when determining the floor. The modified combustion turbine systems are subject to NO_X and SO_2 emission limits under NSPS Subpart KKKK. The modified turbine systems are not subject to any NSPS or NESHAP standard for $PM/PM_{10}/PM_{2.5}$ or GHGs and thus there is no floor of allowable filterable PM or total $PM_{10}/PM_{2.5}$ or GHGs BACT limits.[74]

5.3 BACT Assessment Methodology

The primary document referenced for the traditional "top-down" BACT methodology is U.S. EPA's 1990 *NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting*.[75] U.S. EPA has issued the following guidance documents related to the completion of GHG BACT analyses, which also have relevance to other NSR pollutants. These documents were utilized as resources in completing the BACT evaluation for the proposed projects:

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[72] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with special care for similar reasons.

[73] While not specified as the BACT floor, NESHAP under 40 CFR 63 sometimes regulate NSR pollutants as a surrogate for non-NSR pollutants.

[74] As discussed in Section 4.3.11, NSPS Subpart TTTT does not regulate modified combustion turbine systems.

[75] U.S. EPA, October 1990. https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

- PSD and Title V Permitting Guidance For Greenhouse Gases[76]
- Air Permitting Streamlining Techniques and Approaches for Greenhouse Gases: A Report to the U.S. Environmental Protection Agency from the Clean Air Act Advisory Committee; Permits, New Source Reviews and Toxics Subcommittee GHG Permit Streamlining Workgroup; Final Report[77]
- 2010 Group Reports from the Clean Air Act Advisory Committee, Climate Change Work Group[78]

5.4 BACT "Top-Down" Approach

The following sections present the top-down BACT analysis for each pollutant for which these projects trigger PSD and is specific to each emission unit, unless otherwise specified. The five steps in such an evaluation can be summarized as follows:[79]

- **Step 1.** Identify all possible control technologies;
- **Step 2.** Eliminate technically infeasible control options;
- **Step 3.** Rank the technically feasible control technologies based upon emission reduction potential;
- **Step 4.** Evaluate ranked control technologies based on energy, environmental, and/or economic considerations; and
- **Step 5.** Select BACT.

This process is typically conducted on a unit-by-unit, pollutant-by-pollutant basis. While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. BACT for the proposed projects has been evaluated via this "top-down" approach.

5.4.1 Identification of Potential Control Technologies (Step 1)

Available control technologies with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step. Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. U.S. EPA's RBLC database.
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies.
3. Engineering experience with similar control applications.

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[76] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.

[77] U.S. EPA, September 2012. https://www.epa.gov/sites/production/files/2014-08/documents/ghg-permit-streamlining-final-report.pdf.

[78] https://www.epa.gov/caaac/climate-change-workgroup-reports-and-presentations.

[79] This five step process can be directly applied to GHGs without any significant modifications, per *PSD and Title V Permitting Guidance for Greenhouse Gases*.

4. Information provided by air pollution control equipment vendors with significant market share in the industry.
5. Review of literature from industrial technical or trade organizations.

Trinity Consultants reviewed recently issued air permits and permit files and performed searches of the RBLC database in November 2020 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed project. To ensure that the units being reviewed were comparable in size to the turbine units proposed for modification at the WCP facility, only turbine units with potential generating capacities larger than 100 MW were considered.[80] For combustion turbines, the following categories were searched:[81]

- Permit Data between 1/1/2010 and 11/12/2020
- Process Types[82]
  - 15.110 Large Natural Gas Simple Cycle Combustion Turbines
  - 15.190 Large Liquid Fuel Simple Cycle Combustion Turbines
  - 15.210 Large Natural Gas Combined Cycle Combustion Turbines
  - 15.290 Large Liquid Fuel Combined Cycle Combustion Turbines
  - 15.900 Large Unknown Fuel and/or Cycle Combustion Turbines
  - 16.110 Small Natural Gas Simple Cycle Combustion Turbines
  - 16.190 Small Liquid Fuel Simple Cycle Combustion Turbines
  - 16.210 Small Natural Gas Combined Cycle Combustion Turbines
  - 16.290 Small Liquid Fuel Combined Cycle Combustion Turbines
  - 16.900 Small Unknown Fuel and/or Cycle Combustion Turbines
  - 19.700 Miscellaneous Combustion Turbines
- Process Pollutants: NO_X, $PM/PM_{10}/PM_{2.5}$, CO, VOC, and GHG, including CO_2, CH_4 and N_2O
- Results are for USA only.

Appendix C presents summary tables of relevant BACT determinations for the proposed emission units.

5.4.2 Elimination of Technically Infeasible Control Options (Step 2)

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

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[80] Conservatively ignoring combustion efficiency losses, a 100 MW unit would be the equivalent of 341 MMBtu/hr. This size unit was chosen as a benchmark as it is a size range for which transition from aeroderivative to large frame units generally occur, although there can be aeroderivative units greater than 100 MW.

[81] The proposed combustion turbine system modifications are for simple-cycle combustion turbines. RBLC searches were performed for simple-cycle combustion turbines as well as combined cycle for completeness.

[82] Upon review of records from the RBLC database, certain determinations were made regarding the entries as appropriate. For instance, many entries designated as 15.110 Simple Cycle Combustion Turbines were actually Combined Cycle Combustion Turbines or vice versa. In cases where a clear determination could be made based on the project description or other details provided, the correct details were noted and utilized to include or exclude potentially applicable turbines in the final RBLC review tables. Note also that units combusting fuels in addition to natural gas and fuel oil (such as biomass or ethanol blends) have been removed from the summary list.

5.4.2.1 Demonstrated Technology

Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility. If the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible.[83]

5.4.2.2 Emerging and Undemonstrated Technology

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available."[84] Control technologies in the R&D and pilot scale phases are not considered available. Based on U.S. EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[85] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

5.4.3 Rank of Remaining Control Technologies (Step 3)

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant of interest. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

5.4.4 Evaluation of Most Stringent Control Technologies (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

If necessary, economic analyses compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This

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[83] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.17.

[84] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.18.

[85] NSR Workshop Manual (Draft), Prevention of Significant Deterioration and Nonattainment New Source Review Permitting, page B.18.

method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[86]

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of a replacement catalyst, were included where applicable, while raw material costs were estimated based upon the unit cost and annual consumption. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where *i* is the annual interest rate and *n* is the equipment life in years.

The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For required analyses, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.[87]

5.4.5 Selection of BACT (Step 5)

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

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[86] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf Note that updated sections of the manual relate to NO_X control costs and are not utilized herein. For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

[87] U.S. EPA, OAQPS Control Cost Manual, 6th edition, Section 2, Chapter 1, page 1-52. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

5.5 Defining the Source

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source. Historical practice, as well as recent court rulings, have been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that options that would fundamentally redefine the nature of the source is not appropriate in a BACT determination.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As U.S. EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by U.S. EPA in an opinion on the Prairie State project,

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[88]
>
> ...
>
> *When the Administrator first developed* [U.S. EPA's policy against redefining the source] *in* Pennsauken*, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[89]

Given that some parts of the project are not open for review under BACT, U.S. EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior U.S. EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989], U.S. EPA states the following in Prairie State:

> *For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.* [90]

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[88] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, page 26.

[89] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, page 29.

[90] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

U.S. EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[91]

Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source.

WCP presently operates four simple-cycle natural gas combustion turbines. WCP is proposing the addition of fuel oil combustion capability for these existing turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hr/yr and fuel oil combustion to 2,000 hr/yr. The proposed fuel oil storage capacity on-site could be as much as a 2.5 million gallon vertical fixed-roof storage tank. WCP proposes to continue operating the existing Dry Low NO_X burners on the turbines during gas combustion and proposes to install and operate a water-injection system during fuel oil combustion.

During gas combustion at 100% operating load, the estimated heat input capacity is estimated to be 1,766 Million British Thermal Units per hour (MMBtu/hr) for each turbine, whereas during fuel oil combustion at 100% operating load, the heat input capacity is estimated to be 1,890 MMBtu/hr for each turbine. Collectively, the four turbines will continue to maintain a 680-MW capacity for the site. WCP does not plan to expand overall short-term generating capacity. However, the annual generation (MW-hr) may increase due to both the addition of fuel oil operating capacity and additional run-time capacity on natural gas. WCP will continue to operate as a peaking facility, although operational hours are expected to increase from current levels following these changes.

The BACT selections are based on these design constraints, and any potential control methods that would require OPC to redefine these sources has been explained as such, and were not considered further.

5.6 Combustion Turbines NO_X Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on NO_X emissions from each combustion turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for NO_X.

5.6.1 NO_X Formation – Combustion Turbines

There are five (5) primary pathways of NO_X production from turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. The three most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X.[92] For natural gas-fired units, most NO_X is derived from thermal NO_X. Distillate oils also have low levels of fuel-bound nitrogen (N_2) that contribute to NO_X formation.

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91 *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

92 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

Thermal NO_X is formed mainly via the Zeldovich mechanism where the N_2 and oxygen (O_2) molecules in the combustion air react to form nitrogen monoxide (NO).[93] Most thermal NO_X is formed in high temperature flame pockets downstream from the fuel injectors.[94] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NO_X is formed readily.[95] Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.

Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NO_X.[96] The contribution of prompt NO_X to overall NO_X is relatively small but increases in low-NO_X combustor designs. Prompt NO_X formation is also largely insensitive to changes in temperature and pressure.[97]

Fuel NO_X forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired combustion turbines.[98] Most distillate oils have nitrogen content less than 0.015 percent by weight, resulting in more fuel NO_X generation than natural gas. [99]

In general, technology and emissions performance data could be limited to those turbines within the size range of typical simple-cycle units, and specifically those size of turbines in operation at WCP. U.S. EPA has, in support of federal regulations such as the NSPS for combustion turbines (NSPS Subpart KKKK), reviewed the NO_X emissions performance data for combustion turbines of all sizes and found differing performance data for turbines based on the size of the unit. As quoted by U.S. EPA, per 70 FR 8318 (2/18/05):

> *We identified a distinct difference in the technologies and capabilities between small and large turbines.... the smaller combustion chamber of small turbines provides inadequate space for the adequate mixing needed for very low NO_X emission levels.*

U.S. EPA finalized NSPS Subpart KKKK with a breakpoint in consideration of turbine sizes greater than 850 MMBtu/hr, between 50 MMBtu/hr and 850 MMBtu/hr, and less than 50 MMBtu/hr. Since the WCP units are above the 850 MMBtu/hr size range, only units greater than 850 MMBtu/hr are truly comparable, since as identified by U.S. EPA, there are inherent design differences in units at that size and above that can lead

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[93] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[94] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[95] U.S. EPA, Clean Air Technology Center, *Technical Bulletin: Nitrogen Oxides (NO_X), Why and How They are Controlled*, EPA 456/F-99-006R. November 1999.

[96] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[97] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[98] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[99] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

to inherently lower NO_X emission levels. Therefore, the RBLC review was limited to units of comparable size. For conservatism, WCP focused on units of approximately 100 Megawatts (MW) in size or greater.[100]

NO_X emissions are a potential contributor to secondary particulate formation. Since OPC is conducting a top-down BACT analysis for NO_X for the proposed projects, secondary PM BACT is effectively addressed by reducing the direct emissions of NO_X. As such, secondary PM BACT is not separately addressed.

5.6.2 Identification of NO_X Control Technologies – Combustion Turbines (Step 1)

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies could potentially be employed for the WCP turbines. These technologies use various strategies to chemically reduce NO_X to N_2 with or without the use of a catalyst.

Detailed tables of BACT determinations from the RBLC database are provided in Appendix C. Using the RBLC search, as well as a review of technical literature, potentially applicable NO_X control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:[101]

- Water or Steam Injection
- Dry Low-NO_X (DLN) Combustion Technology (such as SoLoNO$_X$™)
- Good Combustion Practices (Base Case)

Post-combustion control options include:

- EM$_X$™/SCONO$_X$™ Technology
- Selective Catalytic Reduction (SCR)
- SCR with Ammonia Oxidation Catalyst (Zero-Slip™)
- Selective Non-Catalytic Reduction (SNCR)
- Multi-Function Catalyst (METEOR™)

Each control technology is described in detail in the following sections.

5.6.2.1 Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved

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[100] Conservatively ignoring combustion efficiency losses, a 100 MW unit would be the equivalent of 341 MMBtu/hr.

[101] An additional combustion control technology potentially identified was XONON which was offered by Catalytica Energy Systems. Catalytica merged with NZ Legacy in 2007 to form Renergy Holdings Inc. In November 2007, Renergy sold its SCR catalyst and management services business (SCR-Tech, LLC). SCR-Tech, LLC was acquired by Steag Energy Services, LLC in 2016. Based on research, there is no company which currently makes XONON. As such, it is not considered available for this BACT analysis.

solids in the water may damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection can reduce NO_X emissions by over 60%, the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion.[102] Additionally, water/stream injection results in a decrease in combustion efficiency, an increase in power (due to increased mass flow), and an increase in maintenance requirements due to wear.[103]

5.6.2.2 Dry Low-NO_X (DLN) Combustors

The lean premix technology, also referred to as dry low-NO_X combustion technology, is a pollution prevention technology that minimizes NO_X emissions by reducing the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor.[104] In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air decreases the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area.[105] Since NO_X formation rates are an exponential function of temperature, a considerable reduction in NO_X can be achieved by the lean pre-mix system.[106] Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

5.6.2.3 Good Combustion Practices

Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_X emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios.

5.6.2.4 EM_X^{TM} / $SCONO_X$

EM_X^{TM} (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as ammonia (NH_3). The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize NO_X (to potassium nitrate [$K(NO_3)$]) and CO (to CO_2).[107] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$

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102 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

103 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

104 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

105 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

106 AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

107 Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009.
https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

catalyst and release nitrogen gas and water.[108] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The SCONO$_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[109]

Estimates of control efficiency for a SCONO$_X$ system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78% for NO$_X$ reductions down to 2.0 ppm, and even higher NO$_X$ reductions down to 1 ppm for some designs.[110]

5.6.2.5 Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and NO react to form diatomic N_2 and H_2O vapor. The overall chemical reaction can be expressed as:

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

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[111] Optimal temperatures for SCR units ranges from 480°F to 800°F and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200°F.[112] SCR can be used to reduce NO$_X$ emissions from combustion of natural gas and light oils (e.g., distillate). Combustion of heavier oils can produce high levels of particulate, which may foul the catalyst surface, reducing the NO$_X$ removal efficiency.[113] Other considerations include the possibility for ammonia slip, which refers to emissions of unreacted ammonia escaping with the flue gas and its contribution to secondary particulate formation.[114]

5.6.2.6 SCR with Ammonia Oxidation Catalyst (Zero-Slip™)

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) is a refinement on standard post-combustion SCR technology developed by Cormetech and Mitsubishi Power Systems to reduce ammonia slip associated with traditional SCR systems. The Zero-Slip™ technology consists of a second bed of catalyst that is installed

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[108] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[109] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

[110] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

[111] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[112] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[113] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[114] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.)

after the main SCR catalyst to further react NO_X with the ammonia. This results in NO_X emissions on par with standard SCR systems and less ammonia slip (less than 2.0 ppmvd at 15% O_2).[115]

5.6.2.7 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[116] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[117] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X.

5.6.2.8 Multi-Function Catalyst (METEOR™)

METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc., and optimized by Cormetech. The METEOR™ catalyst uses ammonia, similar to standard SCR systems, to reduce NO_X emissions but is also able to reduce CO, VOC, and ammonia emissions using a single catalyst bed (i.e., eliminate the need for a separate oxidation catalyst system if CO and VOC reductions are required), resulting in reduced pressure drop and parasitic load requirements.[118] The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs.[119]

5.6.3 Elimination of Technically Infeasible NO_X Control Options – Combustion Turbines (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

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[115] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 13-14.

[116] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

[117] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

[118] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

[119] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 15-16.

5.6.3.1 Water or Steam Injection Feasibility

Water or steam injection is a NO_X reduction technology that is commonly used to control NO_X emissions when fuel oil is burned, but is not as effective as DLN combustors when firing natural gas.[120] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[121] As the WCP turbines utilize DLN combustors for natural gas combustion that reduce NO_X emissions further than water or steam injection would, water or steam injection is deemed to be infeasible when combusting natural gas, but feasible for purposes of fuel oil combustion.

5.6.3.2 Dry Low NO_X Combustion Technology Feasibility

Dry low NO_X combustion technology is a NO_X control technology that is integral to the combustion turbine. It is determined to be technically feasible for the combustion turbine itself for natural gas combustion and is currently installed on the WCP units. Therefore, DLN combustion technology is included in the following BACT steps for natural gas but represents part of the base case for NO_X performance as it is inherent in the operation of the combustion systems.

5.6.3.3 Good Combustion Practices Feasibility

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the minimization of NO_X emissions from the turbines.

5.6.3.4 EM_X^{TM} / $SCONO_X^{TM}$ Technology Feasibility

The EM_X^{TM}/$SCONO_X^{TM}$ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_X, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X^{TM}/$SCONO_X^{TM}$ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[122] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[123]

Consequently, it is concluded that EM_X^{TM}/$SCONO_X^{TM}$ is not technically feasible for control of NO_X emissions from the WCP turbines.

[120] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12.

[121] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 12.

[122] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[123] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

5.6.3.5 SCR Feasibility

Optimal temperatures for the operation of SCR ranges from 480°F to 800°F and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200°F.[124] Given the exhaust temperature of utility-scale simple-cycle turbines is typically in excess of 1,000°F, use of SCR could be considered technically infeasible for such units.[125] However tempering air could potentially be added to such systems, at significant cost, to allow for use of SCR for such units, as has been done for smaller simple-cycle combustion turbine units. The problem with tempering air is the mass/volume of air required, as it is not just the higher temperature but also the larger volume of air flow involved with larger frame units. Therefore, a cost analysis has been conservatively included in Step 4 to ascertain feasibility.

5.6.3.6 SCR with Ammonia Oxidation Catalyst (Zero-Slip™) Feasibility

Based on WCP's review of available control technologies, to date, the Zero-Slip™ catalyst technology has not been demonstrated on large, utility-size units, with full scale operation demonstrated on a 7.5 MW Solar Taurus combustion turbine.[126] In addition, this technology is essentially SCR with a focus on reducing ammonia slip; accordingly, as SCR has been deemed infeasible, as this technology has not been demonstrated on large, utility size units, and it would not achieve NO_X emission rates lower than that achieved by conventional SCR designs, the Zero-Slip™ technology option is not considered a technically feasible control option.

5.6.3.7 SNCR Feasibility

The temperature range required for effective operation of this technology, 1,600 to 2,000°F, is above the peak exhaust temperature for the WCP turbine units.[127] In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, *Stationary Gas Turbines*, April 2000, shows that SNCR has not been demonstrated on a turbine of this size. Given the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical and reduces the energy efficiency of the generating units, SNCR is eliminated as a technically feasible option for control of NO_X emissions from the WCP turbine systems.

5.6.3.8 Multi-Function Catalyst (METEOR™) Feasibility

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[128,129] A review of the RBLC database for turbines similar to the WCP units did not return any units that use the

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[124] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[125] WCP turbine exhaust temperatures are represented as 1,113°F in the facility's Title V Renewal Application, dated December 11, 2019 (Submittal ID: 288236).

[126] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 14.

[127] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR)*, EPA-452/F-03-031.

[128] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 16.

[129] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst, and the system would have similar technical considerations as a traditional SCR system, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

5.6.4 Summary and Ranking of Remaining NO_X Controls – Combustion Turbines (Step 3)

Of the control technologies available for NO_X emissions, the options technically feasible for each unit are shown in Table 5-2.

Table 5-2. Remaining NO_X Control Technologies

Control Technology	Feasible For Natural Gas	Feasible for Fuel Oil	Estimated Efficiency
Water or Steam Injection	No	**Yes**	>60%
DLN Combustion Technology	**Yes**	No	Base Case
Good Combustion Practice	**Yes**	**Yes**	Base Case
EM_X™/$SCONO_X$™ Technology	No	No	Infeasible
SCR	**Yes**	**Yes**	70-90%
SCR with Zero-Slip™	No	No	Infeasible
SNCR	No	No	Infeasible
METEOR™	No	No	Infeasible

As shown in Table 5-2, the remaining potentially feasible control technologies could include SCR, DLN combustors (natural gas only), water or steam injection (fuel oil only), and good combustion practices. The WCP units already utilize DLN combustors for natural gas combustion.

5.6.5 Evaluation of Most Stringent NO_X Controls – Combustion Turbines (Step 4)

Per Table 5-2, SCR is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling NO_X using SCR for the WCP simple-cycle turbines is approximately $20,000 per ton of NO_X removed based on the detailed cost analysis provided in Appendix D, developed using the methods outlined by the U.S. EPA in the OAQPS guidance manual.[130] As previously discussed, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of the SCR. Therefore, WCP concludes that SCR is not cost effective and is not considered BACT for the Facility's turbines

For fuel oil combustion, the next highest ranked control system is a water or steam injection system. WCP is proposing to install a water injection system on the modified turbines as BACT; hence a cost-effectiveness calculation is not presented. Since the highest remaining control technology for fuel oil combustion has been selected as BACT, no further evaluation of remaining control technologies is required.

[130] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf Note that data from updated sections of the manual related to NO_X control costs is utilized as applicable. For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

For natural gas combustion, DLN combustors are the next highest ranked control and represent the present technology in use for the Facility turbines. Therefore, DLN is selected as BACT for purposes of natural gas combustion.

5.6.6 Selection of Emission Limits and Controls for NO_X BACT – Combustion Turbines (Step 5)

Once the proposed modifications are complete, the combustion turbine systems will be subject to an NSPS Subpart KKKK NO_X emission standard of 15 ppm at 15% O_2 or 0.43 lb/MWh useful output during natural gas combustion; for fuel oil combustion the NO_X emissions standard will be 42 ppm at 15% O_2 or 1.3 lb/MWh useful output. These NSPS Subpart KKKK limits serve as the floor for allowable NO_X BACT limits. Each individual combustion turbine is presently subject to a NO_X limit from NSPS Subpart GG per Condition 3.3.3 of Permit No. 4911-303-0039-V-08-0, however the NSPS Subpart GG limit will no longer apply as a result of applicability of the NSPS Subpart KKKK NO_X limits.[131]

As the selected BACT technology for NO_X emissions relies on DLN combustors and good combustion practices for natural gas, and water injection and good combustion practices for fuel oil combustion, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple-cycle combustion turbines are provided in the RBLC summary table in Appendix C. Review of the RBLC entries confirms that controls for NO_X emissions are typically DLN combustors (natural gas), water or steam injection (fuel oil), and good combustion practices for similarly sized simple-cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries listed in Appendix C provides an indication of what has been established as BACT emission limitations for potentially similar units as those being modified by WCP. The majority of the RBLC database entries relate to the installation of new state-of-the-art simple-cycle units, not modifications of existing simple-cycle units. Given the advancements in turbine design and control systems, it is not anticipated that modification of an older generation turbine system would improve combustion efficiency, controls and performance in a manner that would be comparable to installation of a new, state-of-the-art turbine and controls system. Therefore, for comparison purposes, the RBLC entries of interest for WCP are those which include turbine units deemed to be potentially modified. A review of the RBLC database entries listed in Appendix C reveals that many of the entries do not provide sufficient detail to determine whether the turbines listed were to be newly constructed units or modified units.

For these RBLC entries, further research was conducted as needed using available permits, permit applications, and public documentation. The following qualifying criteria for potentially comparable units to the WCP turbines include:

[131] 40 CFR 60.4305(b)

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;
- Control method includes DLN combustors (natural gas firing) or water injection (fuel oil firing) and does not include control technologies which have been deemed to be infeasible (i.e., SCR, SNCR);
- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

5.6.6.1 Selection of Emission Limits for NO_X BACT - Natural Gas Firing

Table 5-3 includes NO_X RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility. Further research was performed for each of these entries using available permits, permit applications, and public documentation to analyze whether the turbine units are comparable to the existing units at the WCP facility. Findings and notes from this research are further detailed in Sections 5.6.6.1.1 through5.6.6.1.10.

Table 5-3. Natural Gas Simple-Cycle Combustion Turbine NO_X RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	NO_X Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Cunningham Power Plant	NM	5/2/2011	Unknown	Unknown	21 and 30	ppmvd @ 15% O_2	1-hr Avg.	Two simple-cycle combustion turbines utilizing DLN burners. The turbines are capable of operating with or without power augmentation and have specific NO_X limitations for each operating mode (emissions of NO_X are limited to 21 ppmvd without power augmentation and 30 ppmvd with power augmentation). NO_X emission limit excludes periods of startup and shutdown. Permit revises the NO_X BACT ppmvd limit for turbines established in previous PSD Permit No. PSD-NM-622-M2 because turbines have not been able to meet NO_X BACT limits. No modification or change to mass emissions. Former NO_X BACT was at 15 ppmvd w/out power augmentation (normal mode) and 25 ppmvd w/ power augmentation (see RBLC ID NM-0028).
Calcasieu Plant	LA	12/21/2011	1,900 MMBtu/hr Heat Input for Each Turbine	Unknown	17.5	ppmvd @ 15% O_2	Annual Avg.	Two simple-cycle combustion turbines of unknown make and model utilizing DLN combustors. NO_X emission limit excludes periods of startup and shutdown. PSD was triggered due to relaxation of a federally enforceable condition limiting potential emissions below major stationary source thresholds; subsequently revoked. PSD permit issued in 2015 lists NO_X limit as 34.5 ppmvd @ 15% O_2.
Westar Energy – Emporia Energy Center	KS	3/18/2013	405 MMBtu/hr Heat Input for Each Turbine	GE LM6000 PC Sprint	25.0	ppmvd @ 15% O_2	24-hr Rolling Avg.	Four GE LM6000 PC Sprint natural gas fired simple-cycle turbines which are considered aeroderivative turbines. NO_X emission limit excludes periods of startup, shutdown, or malfunction. There are two RBLC database entries for these turbines associated with the 3/18/2013 permit issuance; one entry lists water injection as control for NO_X and the other lists DLN burners as control for NO_X. Permit renewal dated 7/27/2017 lists water injection as control for NO_X.
Westar Energy – Emporia Energy Center	KS	3/18/2013	1,780 MMBtu/hr Heat Input for Each Turbine	GE 7FA	9.0	ppmvd @ 15% O_2	24-hr Rolling Avg.	Three GE 7FA natural gas fired simple-cycle turbines which utilize DLN burners for control. NO_X emission limit excludes periods of startup, shutdown, or malfunction.
Doswell Energy Center	VA	10/4/2016	1,961 MMBtu/hr for Each Turbine	GE Frame 7FA	9.0	ppmvd @ 15% O_2	3-hr Avg.	Authorization to add two 170 MW GE 7FA.03 natural gas fired, simple-cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center (DEC) equipped with low NO_X burners. Both CT-2 and CT-3 were proposed to be brought to DEC from an existing permitted site in Desoto, Florida. They are both similar in age and capability to the existing 190.5 MW GE 7FA.03 simple-cycle combustion turbine (CT-1) at the facility. CT-1 was added in a PSD permit dated April 7, 2000 and last amended on September 30, 2013. Emissions of NO_X are limited to 9 ppmvd excluding periods of startup, shutdown, and tuning.
Puente Power	CA	10/13/2016	262 MW	Unknown	2.5	ppmvd @ 15% O_2	1-hr Avg.	One 262 MW gas turbine.

Facility Name	State	Permit Issuance	System Size	Turbine Model	NO_X Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Waverly Facility	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	9.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of DLN burners when firing natural gas. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included.
Waverly Power Plant	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	9.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of DLN burners when firing natural gas. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.
Cameron LNG Facility	LA	2/17/2017	1,069 MMBtu/hr Heat Input for Each Turbine	Unknown	15.0	ppmvd @ 15% O_2	1-hr Avg.	Gas turbines which utilize DLN burners as control.
Mustang Station	TX	8/16/2017	163 MW	GE 7FA	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	One 163 MW GE 7FA turbine (Unit No. 6) which was constructed in 2013 and utilizes DLN burners for control. Permit involved increasing the turbine hours of operation to 3,000 hours per year. NO_X emission limit excludes periods of maintenance, startup, and shutdown.
Jackson County Generators	TX	1/26/2018	230 MW for Each Turbine	Unknown	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	Four natural gas fired simple-cycle combustion turbines which utilizes DLN burners for control. NO_X emission limit excludes periods of startup and shutdown.
Ector County Energy Station	TX	8/17/2020	Unknown	Unknown	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	Two simple-cycle gas turbines equipped with DLN burners for control. Emission limit for NO_X applies to normal operations.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

The following sections include detailed discussions of permitting actions and highlight the commonalities or differences between the turbines included in the Table 5-3 RBLC entries and the WCP turbine units. Additional details are included in these sections which were not available in the RBLC database entries.

5.6.6.1.1 Cunningham Power Plant

Southwestern Public Service Company is permitted to operate the Cunningham Station Power Plant, which incorporates the use of two 115 MW combustion turbines which were constructed in 1997. The turbines utilize DLN burners for control of NO_X and are capable of operating with or without power augmentation, in which power output is increased by lowering air temperature through water injections into the compressor. On May 2, 2011, the Cunningham Station Power Plant was issued an NSR permit in which BACT limits for NO_X were increased.[132] However, upon further investigation of the facility's historical permits, it was determined that the turbine units are Westinghouse 501D5A model turbines. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, WCP maintains that the Westinghouse model turbines are not necessarily an appropriate comparison for a GE 7FA turbine. However, it is worth noting that the permit issued on May 2, 2011 established a BACT emission limitation for NO_X of 21 ppmvd (without power augmentation) at 15 percent O_2 which excludes periods of startup and shutdown. This NO_X emission limitation is considered achievable for the existing WCP turbine units. A revised NSR permit was issued on May 23, 2012 which maintained the previously described BACT emission limits for NO_X.[133]

5.6.6.1.2 Calcasieu Plant

Calcasieu Power, LLC, received a state preconstruction and Part 70 operating permit from the Louisiana Department of Environmental Quality (LDEQ) on October 21, 1999 for the operation of a peaking power plant consisting of two natural gas fired, simple-cycle combustion turbines with heat inputs of 1,900 MMBtu/hr.[134] Each of the combustion turbines utilize DLN combustors for emissions control. Effective March 2008, Entergy Gulf States Louisiana (Entergy), LLC purchased Calcasieu Power, LLC and the facility was thereafter referred to as the Calcasieu Plant.[135]

Entergy received an initial PSD permit and a revised Title V permit on December 21, 2011 which allowed for the two combustion turbines to increase annual operating hours.[136] The initial PSD permit provided a BACT emission limit for NO_X during normal operation of 17.5 ppmvd corrected to 15% O_2 for each of the two turbines and required emissions of NO_X to be monitored by CEM. However, the changes associated with the December 11, 2011 Title V and PSD permits were never incorporated, and Entergy requested the revocation of the PSD permit.[137] On January 25, 2013, the LDEQ issued Permit No. 0520-00219-V4 which removed the changes authorized per the December 21, 2011 Title V permit as well as increased the maximum hourly firing rate of the turbines to 2,200 MMBtu/hr. A new PSD permit and revised Title V permit were issued on June 1, 2015 which allowed for an increase in the combined operating time for the turbines and allowed for additional periods of startup/shutdown time. The June 1, 2015 PSD permit also established BACT emission

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[132] NSR Permit No. PSD-NM-622-M3 issued by the NMED to the Southwester Public Service Company on May 2, 2011.

[133] NSR Permit No. PSD-NM-622-M4 issued by the NMED to the Southwester Public Service Company on May 23, 2012.

[134] Permit No. 0520-00219-V0 issued by the LDEQ to Dynegy Operating Company, Inc. – Calcasieu Power, LLC, October 21, 1999.

[135] Per Notification of Ownership, Facility Name, and Operator Change submitted to the LDEQ on May 12, 2008.

[136] Permit Nos. 0520-00219-V3 and PSD-LA-746 issued by the LDEQ to Entergy Gulf States LA LLC, December 21, 2011.

[137] Per Title V Permit Renewal Renewal Application submitted to the LDEQ on April 11, 2012.

limits for NO_X of 34.3 ppmvd corrected to 15% O_2 during normal operation for each of the two turbines and required emissions of NO_X to be monitored by CEM.

Although the make and model of the Calcasieu Plant turbines is not known, WCP anticipates that the NO_X emission limit of 34.3 ppmvd is conservative and higher than other comparable BACT limitations.

5.6.6.1.3 Emporia Energy Center

Westar Energy received an Air Emissions Source PSD Construction Permit for the Emporia Energy Center on April 17, 2007 (modified May 5, 2011).[138] The Emporia Energy Center is fossil fuel power plant which consists of four GE LM6000 PC natural gas fired, simple-cycle combustion turbines equipped with water injection and three GE 7FA natural gas fired, simple-cycle combustion turbines which utilize DLN burners.

The GE LM6000 PC model turbines are classified as aeroderivative gas turbines.[139] Aeroderivative turbines have a much smaller power output than what would be expected from a large frame unit such as a GE 7FA turbine; therefore, the GE LM6000 PC turbines cannot be considered relatively comparable units to reference for selection of BACT emission limits based on size.

The Emporia Energy Center does operate three GE 7FA simple-cycle turbines with heat inputs of 1,780 MMBtu/hr which were authorized for construction in 2007. The GE 7FA turbines would be considered comparable in size and age to the existing units operated by WCP, and because both units are GE 7FA model turbines, it can be assumed that the turbines would have similar emission profiles. On March 18, 2013, the Kansas Department of Health and Environment (KDHE) issued an amendment to the prior PSD permit to add tuning language to allow for the periodic tuning of the GE 7FA combustion turbines.[140] The GE 7FA turbines at the Emporia Energy Center are subject to a NO_X emission limitation of 9 ppmvd corrected to 15% O_2 on a 24-hr rolling average which excludes startup, shutdown, and malfunction periods. This BACT emission limit for NO_X should be considered an achievable limit for the proposed modifications to the existing turbines at the WCP facility.

5.6.6.1.4 Doswell Energy Center

On October 4, 2016, the Virginia Department of Environmental Quality (VDEQ) issued a permit which authorized the addition of two natural gas fired GE 7FA simple-cycle combustion turbines. Each turbine has a heat input of 1,961 MMBtu/hr and utilizes low NO_X burners for control. The two turbines were originally constructed in 2001 and were to be relocated from an existing permitted site in Desoto, Florida to the Doswell Energy Center. Based on turbine age, model, and size these units should be considered comparable to the existing WCP turbines. Therefore, it is reasonable to assume that this modification is comparable to the proposed modification to the existing WCP turbine units. Each of the simple-cycle turbines added to the Doswell Energy Center are subject to BACT emission limitations for NO_X of 9 ppmvd at 15% O_2 on a 3-hour average basis (averaging time based on the PSD permit), except during periods of startup, shutdown, and tuning. This is an achievable emission limitation for the existing WCP turbines at the WCP facility. Revised PSD permits for the two simple-cycle combustion turbines were issued on May 31, 2018 and July 30, 2018. The issuance of the July 30, 2018 PSD permit revised the averaging period for the BACT emission limit for NO_X from 3-hour averaging basis to a 1-hour averaging basis.

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[138] Permit Nos. C-7072 and C-9132 issued by the KDHE on April 17, 2007 and May 5, 2011, respectively.

[139] https://www.ge.com/power/gas/gas-turbines/lm6000

[140] Permit No. C-10656 issued by the KDHE for the Emporia Energy Center on March 18, 2013.

5.6.6.1.5 Puente Power

The RBLC database entry for the Puente Power facility contained insufficient information needed to determine comparability relative to the proposed modified units at the WCP facility. Upon further research into publicly available information, it was discovered that the Puente Power facility was proposed for construction in 2015 in Ventura County California. The proposed facility would consist of one natural gas fired, simple-cycle GE 7HA.01 turbine with a net-nominal 262 MW generating capacity.[141] However, in 2018, the California Energy Commission terminated the 2015 application to construct the facility and the project was voided.[142] Therefore, as this project involved new units that were never constructed, the Puente Power RBLC database entry is not considered further in these BACT analyses.

5.6.6.1.6 Waverly Facility (Waverly Power Plant)

In 1999, Pleasants Energy LLC submitted a permit application to the West Virginia Department of Environmental Protection (WVDEP) to construct a peaking power facility in Waverly, West Virginia which would utilize two GE 7FA natural gas fired, simple-cycle combustion turbines capable of generating 300 MW. Natural gas was to be the primary fuel and fuel oil would be used as back-up.[143] The two combustion turbines were installed in 2001 and utilize DLN burners when firing natural gas and water injection for control of NO_X when firing fuel oil.[144] The facility was issued a Permit to Modify on November 24, 2015 which allowed for the addition of two TurboPhase systems (8 engines) to allow for increased generator output.[145] The facility received an additional Permit to Modify on January 23, 2017, which allowed for the relaxation of limits which were originally imposed to maintain the synthetic minor status of the source for PSD permitting purposes.[146]

The authorization to operate the TurboPhase engines was removed by way of the Permit to Modify issued on March 13, 2018.[147] The Permit to Modify also allowed for the installation of "Advanced Gas Path" technology to the existing GE 7FA turbines which increased the maximum heat input of each turbine. The RBLC database entry for the issuance of the March 13, 2018 Permit to Modify states that the addition of the "Advanced Gas Path" technology to the combustion turbines was defined as a change in the method of operation that resulted in a major modification to the turbines. According to information available on General Electric's website, the incorporation of GE's "Advanced Gas Path" technology to GE 7FA turbines results in "increased output, efficiency, and availability, while reducing fuel consumption and extending gas turbine assets."[148]

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[141] California Energy Commision, *Puente Power Project Final Staff Assessment Part 1*, Docket No. 15-AFC-01, Publication No. CEC-700-2016-006-FSA, December 8, 2016.

[142] Wendy Leung, "NRG proposal to build Puente Power Project on Oxnard coast is dead," *Ventura County Star*, December 17, 2018, https://www.vcstar.com/story/news/2018/12/17/power-plant-nrg-energy-inc-california-energy-commission-oxnard/2266774002/. (accessed January 21, 2021).

[143] West Virginia Department of Environmental Protection, Division of Air Quality, *Preliminary Determination/Fact Sheet for the Construction of Pleasants Energy, LLC's Waverly Power Plant located in Waverly, Pleasants County, WV*, Permit No. R14-0034, September 29, 2016.

[144] Per Section 1.1 of Permit No. R30-07300022-2020 issued by the WVDEP for the Waverly Facility on June 10, 2020.

[145] Permit No. R13-2373B issued by the WVDEP for the Waverly Facility on March 18, 2013.

[146] Permit No. R14-0034 issued by the WVDEP for the Waverly Facility on January 23, 2017.

[147] Permit No. R14-0034A issued by the WVDEP for the Waverly Facility on January 13, 2018.

[148] https://www.ge.com/power/services/gas-turbines/upgrades/advanced-gas-path?gecid=press_release.

The Waverly facility GE 7FA turbines have been modified since installation, albeit in ways that are not like the proposed WCP modifications. The BACT emission limits established per the 2013 and 2017 permitting actions is 9 ppm NO_X at loads of 60% or higher based on a 30-day rolling average, excluding periods of startup and shutdown. This emission limit should be considered achievable for the existing turbines at the WCP facility.

5.6.6.1.7 Cameron LNG Facility

On October 1, 2013, the Cameron LNG Facility was issued an initial PSD permit and revised Title V permit which authorized the construction of additional equipment which included six refrigeration compressor turbines with heat inputs of 1,069 MMBtu/hr each.[149] The facility was again issued revised PSD and Title V permits on March 3, 2016 which authorized the construction of additional equipment, including four refrigeration compressor turbines with heat inputs of 1,069 MMBtu/hr each.[150] The RBLC database entry for the Cameron LNG Facility is associated with the February 17, 2017 issuance of revised PSD and Title V permits which incorporated two diesel tanks into the PSD permit and also incorporated administrative updates to both the PSD and Title V permits.[151] The RBLC entry for the Cameron LNG Facility did not provide sufficient detail to make a determination of comparability for these turbines. However, upon further review of PSD and Title V permits, it is clear that the turbines at the Cameron LNG Facility were constructed for the purposes of refrigeration compression rather than for power generation, and therefore they cannot be considered comparable to the existing turbine units at the WCP facility. Therefore, the Cameron LNG Facility RBLC database entry is not considered further in these BACT analyses.

5.6.6.1.8 Mustang Station

Mustang Station commenced operation of a 168 MW GE 7FA simple-cycle combustion turbine (Unit 6) in 2013. The turbine unit utilizes DLN burners for control of NO_X emissions. The facility was issued an amended PSD permit on August 8, 2016 by the Texas Commission on Environmental Quality (TCEQ) which allowed for the combustion turbine to increase annual operation to 3,000 hours per year.[152] Because the turbine was built in 2013, the equipment at the Mustang Station represents new turbines, albeit GE 7FA turbines of a more modern design than those installed and operating at the WCP facility. The turbine at the Mustang Station may not be considered comparable to existing units at the WCP facility which began operation in 2001, yet the established BACT emission limitation, 9 ppm NO_X corrected to 15 percent O_2 on a rolling 3-hour average (excluding periods of maintenance, startup, and shutdown) is considered achievable for the existing WCP turbine units.

5.6.6.1.9 Jackson County Generators

The Southern Power Company submitted an Air Preconstruction Permit General Application to the TCEQ in July 2014 for the construction of the Jackson County Generating Facility which would include four 230 MW natural gas fired simple-cycle combustion turbines with DLN burners.[153] An initial permit was issued by the

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[149] Permit Nos. PSD-LA-766 and 0560-00184-V5 issued by the LDEQ to Cameron LNG, LLC on October 1, 2013.

[150] Permit Nos. PSD-LA-766(M2) and 0560-00184-V7 issued by the LDEQ to Cameron LNG, LLC on March 3, 2016.

[151] Permit Nos. PSD-LA-766(M3) and 0560-00184-V8 issued by the LDEQ to Cameron LNG, LLC on February 17, 2017.

[152] Permits 72579, PSDTX1080M1, and GHGPSDTX138 issued by the TCEQ to Cameron LNG, LLC on October 1, 2013.

[153] Per the Air Preconstruction Permit General Application submitted by the Southern Power Company to TCEQ on July 11, 2014.

TCEQ on February 2, 2018.[154] Upon further investigation of the February 2018 permit, it was determined that the proposed units are Siemens F5 model turbines. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, WCP maintains that the Siemens F5 model turbines are not necessarily an appropriate comparison for a GE 7FA turbine. However, it is worth noting that the permit issued on February 2, 2018 established a BACT emission limitation for NO_X of 9 ppmvd at 15 percent O_2 on a rolling 3-hour average which excludes periods of startup and shutdown. This NO_X emission limitation is considered achievable for the existing WCP turbine units.

5.6.6.1.10 Ector County Energy Station

The Ector County Energy Station was issued initial permits for the construction of two simple-cycle turbine generating units on August 1, 2014.[155] Subsequent revisions to the initial permit were issued in 2014, 2017, 2018, 2019, and 2020. The permit allowed for the construction of two GE 7FA.03 or 7FA.05 combustion turbines capable of generating 165-193 MW of output; per more recent documentation is appears the GE 7FA.03 engines were installed. Each of the turbines were to be controlled using DLN burners. An RBLC database entry associated with a permit issuance dated 8/17/2020 states that hours of operation for the existing combustion turbines were increased per this permitting action. As the initial air permit was received in 2014, it is reasonable to assume that the turbines at the Ector County Energy Station are newer state-of-the-art simple-cycle combustion turbine units which would not necessarily be comparable to the existing WCP units. However, the units are subject to a 9 ppmvd NO_X limit at 15% O_2 on a rolling 3-hour average which excludes periods of startup and shutdown. This NO_X emission limitation is considered achievable for the existing WCP turbine units.

5.6.6.1.11 Summary – Natural Gas NO_X BACT

The anticipated NO_X BACT for natural gas firing would be good combustion practices and the use of DLN combustion technology. As was previously discussed, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-3 are not necessarily directly comparable to the WCP units. Table 5-4 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-3 are comparable to the WCP units based on these factors.

Table 5-4. Unit Comparability for NO_X Assessment – Natural Gas Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	NO_X Emission Limit	Averaging Period
Cunningham Station Power Plant	Increase NO_X BACT Emission Limits	No, Westinghouse 501D5A	No	Not Comparable	
Calcasieu Plant [1]	Increase hours, heat input	Unknown	Yes	34.5 ppmvd @ 15% O_2	Annual Avg.
Emporia Energy Center – GE LM6000PC Units (Water Injection) [2]	N/A	No	No	Not Comparable	

[154] Permits Nos. 121917 and PSDTX1422 issued by the TCEQ to the Southern Power Company on February 2, 2018.

[155] Permits Nos. 110423 and PSDTX1366 issued by the TCEQ to Invenergy Thermal Development LLC on August 1, 2014.

Site	Modification?	GE Frame 7 Turbine?	Comparable?	NO_X Emission Limit	Averaging Period
Emporia Energy Center – GE LM6000PC Units (DLN) [2]	N/A	No	No	Not Comparable	
Emporia Energy Center – GE 7FA	No (New in 2007) Added Tuning Requirements in 2013	Yes	No (New Unit) Yes (Engine Type)	9.0 ppmvd @ 15% O_2	24-hr Rolling Avg.
Doswell Energy Center	Turbine Relocation	Yes	Yes	9.0 ppmvd @ 15% O_2	3-hr Avg.(2016) 1-hr Avg (2018)
Puente Power	No - New	Yes	No	Application Revoked	
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	9.0 ppmvd @ 15% O_2	30-day Rolling Avg.
Waverly Facility - 2018	Increase heat input	Yes	Potentially	9.0 ppmvd @ 15% O_2	30-day Rolling Avg.
Cameron LNG Facility	No – New	Compressor Turbines	No	Not Comparable	
Mustang Station	Increase hours	Yes, 2013 install	Potentially	9.0 ppmvd @ 15% O_2	3-hr Rolling Avg.
Jackson County Generators	No	No, Siemens F5	No	Not Comparable	
Ector County Energy Center	No (New in 2014), increased hours in 2020	Yes	Potentially	9.0 ppmvd @ 15% O_2	3-hr Rolling Avg.

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed a BACT limit for NO_X of 17.5 ppmvd @ 15% O_2. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and established the BACT limit for NO_X as 34.5 ppmvd @ 15% O_2.

[2] Please note that the RBLC database entries in Appendix C include two separate entries for the GE LM6000 PC Sprint turbines at the Emporia Energy Center. One entry lists water injection as a control method and the other lists dry low NO_X burners as the control method.

As was discussed in Section 5.2.4, BACT is to be set at the lowest value that is achievable. Per Table 5-4, the remaining potentially comparable turbine units each have NO_X emission limits for BACT of 9 ppmvd at 15% O_2 or greater. A NO_X limit of 9 ppmvd at 15% O_2 is an achievable emission limitation for the turbine units at the WCP facility. **Therefore, WCP proposes a BACT limit for NO_X of 9 ppmvd at 15% O_2 on a 4-hr averaging basis when firing natural gas, excluding periods of startup and shutdown.** A 4-hr averaging period as documented per CEMS is proposed for consistency with the NSPS Subpart KKKK monitoring requirements and to ensure WCP's ability to demonstrate continuous compliance and reasonably aligns with the other BACT limitations reviewed per Table 5-4.

5.6.6.2 Selection of Emission Limits for NO_X BACT – Fuel Oil Firing

Table 5-5 includes NO_X RBLC database entries for turbine units combusting fuel oil which are potentially comparable to the existing units at the WCP facility. Further research was performed as necessary for entries using available permits, permit applications, and public documentation to analyze whether the turbine units are comparable to the existing units at the WCP facility. Findings and notes from this research are further detailed in Section 5.6.6.1.6 and 5.6.6.2.1.

Table 5-5. Fuel Oil Simple-Cycle Combustion Turbine NO_X RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	NO_X Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Wolverine Power	MI	6/29/2011	540 MMBtu/hr Heat Input	Unknown	0.16	lb/MMBtu	Test protocol will specify avg. time	One ULSD fired turbine generator which will be used to start the plant when there is no power available from the electric grid and the plant must be brought back into service. Turbine utilizes good combustion control technology.
Waverly Facility [2]	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	49.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of water injection for control of NO_X when firing fuel oil. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included.
Waverly Power Plant [2]	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	42.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of water injection for control of NO_X when firing fuel oil. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for NO_X associated with the turbine unit for fuel oil firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for NO_X existed for the associated turbine units when firing fuel oil. The established BACT limits for NO_X were added to this table.

5.6.6.2.1 Wolverine Power

Wolverine Power Supply Cooperative, Inc was issued a permit to install a coal fired power plant in Presque Isle County, Michigan by the Michigan Department of Environmental Quality (MDEQ) on June 29, 2011.[156] The permit was subsequently revised on July 12, 2011. The permitted sources include a 540 MMBtu/hr ULSD fired turbine generator of unknown make and model which would be used to start the plant when there is no power available from the electric grid. The turbine was permitted for 500 hours of operation annually and would utilize good combustion control technology only (i.e., did not require water injection). However, plans to build the coal-fired power plant were discontinued in 2013 and the project was voided.[157] Because the turbine at the Wolverine Power facility was never built, the BACT limit has not been demonstrated in practice and the associated RBLC database entry is not considered further in these BACT analyses.

5.6.6.2.2 Summary – Fuel Oil NO_X BACT

The anticipated NO_X BACT for fuel oil firing would be good combustion practices and the use of water or steam injection. Table 5-6 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-5 are comparable to the WCP units based on these factors.

Table 5-6. Unit Comparability for NO_X Assessment – Fuel Oil Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	NO_X Emission Limit	Averaging Period
Wolverine Power	No – New	Unknown	No	Project Voided – Facility Was Not Built	
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	49 ppmvd	30-day Rolling Avg.
Waverly Facility - 2018	Increase heat input	Yes	Potentially	42 ppmvd	30-day Rolling Avg.

For the potentially comparable turbine units listed in Table 5-6, the 42 ppmvd requirement is similar to the BACT floor limitation established per NSPS Subpart KKKK of 42 ppm at 15% O_2 or 1.3 lb/MWh useful output when firing fuel oil. Therefore, this NSPS Subpart KKKK limit represents the proposed NO_X BACT limit for the WCP turbines when combusting fuel oil. Compliance with the NSPS KKKK NO_X emission limit is determined on a 4-hour rolling average basis.[158] **As such, WCP proposes a BACT limit for NO_X of 42 ppmvd at 15% O_2 on a 4-hour rolling average basis when firing fuel oil, excluding periods of startup and shutdown**. Compliance will be demonstrated via CEMS.

[156] Permit No. 317-07 issued by the MDEQ on June 29, 2011 and revised on July 12, 2011.

[157] "Wolverine Power scraps plan to build coal-fired plant," *UpNorthLive News on ABC*, Sinclair Broadcast Group, Inc., December 18, 2013, https://upnorthlive.com/news/neighborhood/wolverine-power-scraps-plan-to-build-coal-fired-plant. (accessed January 21, 2021).

[158] 40 CFR 60.4350(g), 40 CFR 60.4380(b)(1)

5.6.6.3 Secondary BACT Limit – NO_X

The proposed primary BACT limits of 9.0 ppmvd and 42 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different NO_X emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. WCP therefore proposes a secondary BACT limit per turbine of 152.7 tpy on a rolling 12-month basis to ensure the minimization of emissions during startup/shutdown periods.

5.7 Combustion Turbines Filterable PM and Total PM_{10}/$PM_{2.5}$ Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on particulate related emissions from each simple-cycle turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits selected as BACT for filterable PM and total PM_{10}/$PM_{2.5}$.

While BACT emission limits for PM_{10} and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM or PM_{10} also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable PM_{10} will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to PM_{10} are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed projects is due to NO_X emissions from each combustion turbine. As WCP is completing a BACT review for NO_X as part of this application, secondary PM BACT formation from NO_X emissions will be indirectly addressed. The proposed project does not trigger PSD review for the $PM_{2.5}$ precursor SO_2, as project emissions increases are less than the applicable SO_2 SER. As such, secondary PM BACT is not required to be addressed separately.

5.7.1 PM Formation – Combustion Turbines

Filterable PM, PM_{10} and $PM_{2.5}$ emissions from gas or distillate oil combustion result primarily from incomplete combustion and by ash and sulfur in the fuel.[159] Combustion of natural gas or distillate oil generates low PM emissions in comparison to other fuels due to the low ash and sulfur contents of these fuels.

In contrast to filterable particulate, condensable particulate is the portion of PM emissions that exhausts from the stack in gaseous form but condenses to form particulate matter once mixed with the cooler ambient air. Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics. A combustion turbine operating without an SCR will have lower condensable PM emissions than a similar unit operating with an SCR.

5.7.2 Identification of PM Control Technologies – Combustion Turbine (Step 1)

The following PM_{10}/$PM_{2.5}$ control technologies were identified based on RBLC search (per the search criteria specified in Section 5.4.1), a limited review of information published in technical journals, and experience in conducting control technology reviews for similar types of equipment. Taking into account the physical and operational characteristics of the units, the candidate control options for particulate matter reduction include:

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[159] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000.

- Multicyclone
- Wet Scrubber
- Electrostatic Precipitator (ESP)
- Baghouse
- Low sulfur fuel
- Good combustion and operating practices

5.7.2.1 Multicyclone

Multicyclones consist of several small cyclones operating in parallel. The cyclone creates a double vortex inside its shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls. While this is effective for larger particles, smaller particles tend to be overtaken by the fluid drag force of the air stream and will depart the cyclones with the exiting air stream. The particulate removal in cyclones can be improved by having more complex gas flow patterns.[160] The control efficiency range for high efficiency single cyclones is 30 - 90% for PM_{10} and 20 - 70% for $PM_{2.5}$. The use of multicyclones leads to greater PM control efficiency than from a single cyclone, resulting in control efficiencies in the range of 80-95% for particles greater than 5 microns in diameter (PM_5).[161] Multicyclones in parallel can typically handle a higher flowrate when compared to a single cyclone unit, up to approximately 106,000 standard cubic feet per minute (scfm). The allowable inlet gas temperature for a cyclone is limited by the type of construction material, but can be as high as 540°C (1,000°F).[162] Cyclones are generally used as precleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower control efficiency of smaller particles from a cyclone.[163]

5.7.2.2 Wet Scrubber

Wet (in particular, venturi) scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The PM collection efficiencies of Venturi scrubbers range from 70% to greater than 99%, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 µm ($PM_{0.5}$) to 5 µm (PM_5). Inlet gas temperatures for wet scrubbers usually range from 4 to 400°C (40 to 750°F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.[164]

5.7.2.3 ESP

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked (“rapped”), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, gas temperature, and plate dimensions. An ESP can be designed for either dry or

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[160] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005.

[161] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[162] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[163] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

[164] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Venturi Scrubbers, EPA-452/F-03-017.

wet applications.[165] An ESP can generally achieve approximately 99-99.9% reduction efficiency for PM emissions. Typical ESPs can handle approximately 1,000 to 100,000 scfm, at high temperatures up to 700°C (1,300°F).[166]

5.7.2.4 Baghouse (Fabric Filter)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags suffered in the cleaning process.[167] Typically, gas temperatures up to 260°C (500°F) can be accommodated routinely in a baghouse. The fabric filters have relatively high maintenance requirements (for example, periodic bag replacement), and elevated temperatures above the designed temperature can shorten the fabric life. Additionally, a baghouse/fabric filter cannot be operated in moist environments where the condensation of moisture could cause the filter to be plugged, reducing efficiency. Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[168]

Depending on the need, baghouses are available as standard units from the factory, or custom baghouses designed for specific applications. Standard baghouses can typically handle 100 to 100,000 scfm; while custom baghouses are generally larger, ranging from 100,000 to over 1,000,000 scfm.[169]

5.7.2.5 Low Sulfur Fuels

Combusting pipeline-quality natural gas with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form H_2SO_4. Similarly, use of ultra-low sulfur diesel fuel oil also minimizes H_2SO_4 formation leading to lower particulate emissions compared to other fuel oils.

5.7.2.6 Good Combustion and Operating Practices

Good combustion and operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

A properly operated combustion unit will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

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[165] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[166] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Pipe Type, EPA-452/F-03-027.

[167] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[168] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

[169] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

5.7.3 Elimination of Technically Infeasible PM Control Options – Combustion Turbines (Step 2)

All four of the add-on control technologies (multicyclones, wet scrubbers, ESPs, and baghouses) are technically infeasible for filterable particulate from natural gas combustion. Although the add-on control technologies identified are utilized in a number of processes to control particulate emissions, none of these add-on control technologies are applicable to natural gas-fired or fuel oil fired combustion turbines. Combustion of natural gas and ultra-low sulfur diesel generates relatively low levels of particulate emissions in comparison to other fuels due to the low ash and sulfur contents. In addition, turbines operate with a significant amount of excess air, which generates large exhaust flow rates. The low level of particulate emissions combined with the large exhaust gas volume results in very low concentrations of particulate.

Due to the low particulate concentration in the exhaust gas, add-on filterable particulate controls would not provide any significant degree of emission reduction for the combustion turbines and are therefore not considered further in this analysis.[170]

5.7.4 Summary and Ranking of Remaining PM Controls – Combustion Turbines (Step 3)

Of the control technologies available for $PM_{10}/PM_{2.5}$ emissions, the options technically feasible for each unit are shown in Table 5-7**.**

Table 5-7. Remaining Particulate Matter Control Technologies

Control Technology	Technically Feasible for Combustion Turbine
Multicyclones	No
Wet Scrubber	No
ESP	No
Baghouse	No
Low Sulfur Fuel	Yes
Good Combustion and Operating Practices	Yes

As shown in Table 5-7, the remaining feasible control technologies include low sulfur fuels and good combustion and operating practices. Good combustion and operating practices in conjunction with low sulfur natural gas or ultra-low sulfur diesel combustion represents the base case for the combustion turbines. Therefore, as this is the highest-ranking feasible control remaining, it is selected as BACT.

5.7.5 Evaluation of Most Stringent PM Controls – Combustion Turbines (Step 4)

As stated previously, good combustion and operating practices with low sulfur natural gas or ultra-low sulfur diesel for the combustion turbines was determined as the most stringent filterable PM and total $PM_{10}/PM_{2.5}$ control that is a technically feasible option.

[170] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, page 43.

5.7.6 Selection of Emission Limits and Controls for PM BACT – Combustion Turbines (Step 5)

The simple-cycle combustion turbines will not be subject to any NSPS or NESHAP standard for $PM/PM_{10}/PM_{2.5}$ and thus there is no floor of allowable $PM/PM_{10}/PM_{2.5}$ BACT limits. The units are also not subject to any PM emission limit per the GRAQC.

As the selected BACT for particulate matter emissions relies on good combustion and operating practices in conjunction with the use of low sulfur natural gas or ultra-low sulfur diesel, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas and fuel oil fired simple-cycle systems are provided in Appendix C. Review of the RBLC entries confirms that add-on control for particulate emissions is not required for natural gas-fired or fuel oil fired simple-cycle combustion turbines. Typical listings denote "good combustion practices" or similar variants. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C to identify potentially comparable units to the WCP turbines:

- Turbine is existing and proposed for a modification; exclude units proposed for initial construction;
- Units are similar GE Frame 7 units, and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

5.7.6.1 Selection of Emission Limits for PM BACT - Natural Gas Firing

Table 5-8 includes PM RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility.

Table 5-8. Natural Gas Simple-Cycle Combustion Turbine PM RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	PM Emission Limit [1]	Units [1]	Notes
Cunningham Power Plant	NM	5/2/2011	Unknown	Unknown	5.4 (FPM_{10})	lb/hr	Two simple-cycle combustion turbines utilizing good combustion practices as a control method. The turbines are capable of operating with or without power augmentation. Permit revises the NO_X BACT ppmvd limit for turbines established in previous PSD Permit No. PSD-NM-622-M2 because turbines have not been able to meet NO_X BACT limits.
Calcasieu Plant	LA	12/21/2011	1,900 MMBtu/hr Heat Input for Each Turbine	Unknown	17.0 (TPM_{10} and $TPM_{2.5}$)	lb/hr	Two simple-cycle combustion turbines of unknown make and model which utilizes pipeline natural gas as a control method. PSD was triggered due to relaxation of a federally enforceable condition limiting potential emissions below major stationary source thresholds; subsequently revoked. PSD permit issued in 2015 lists the emission limitation for PM as 20 lb/hr.
Westar Energy – Emporia Energy Center	KS	3/18/2013	405 MMBtu/hr Heat Input for Each Turbine	GE LM6000 PC Sprint	6.0 (TPM and TPM_{10})	lb/hr	Four GE LM6000 PC Sprint natural gas fired simple-cycle turbines which are considered aeroderivative turbines and utilize pipeline quality natural gas as a control method.
Westar Energy – Emporia Energy Center	KS	3/18/2013	1,780 MMBtu/hr Heat Input for Each Turbine	GE 7FA	18.0 (TPM and TPM_{10})	lb/hr	Three GE 7FA natural gas fired simple-cycle turbines which utilize pipeline quality natural gas as a control method.
Pueblo Airport Generating Station	CO	5/30/2014	375 MMBtu/hr Heat Input	GE LM6000	4.8 (TPM_{10} and $TPM_{2.5}$)	lb/hr	One GE LM6000 simple-cycle gas turbine (Unit 6 – CT08) which is considered an aeroderivative unit and utilizes pipeline quality natural gas and good combustor design as control methods.
Doswell Energy Center	VA	10/4/2016	1,961 MMBtu/hr for Each Turbine	GE Frame 7FA	0.0051 (10.0 lb/hr) (FPM) 0.00612 (12.0 lb/hr) (TPM_{10} and $TPM_{2.5}$)	lb/MMBtu	Authorization to add two 170 MW GE 7FA.03 natural gas fired, simple-cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center (DEC). Both CT-2 and CT-3 were proposed to be brought to DEC from an existing permitted site in Desoto, Florida. They are both similar in age and capability to the existing 190.5 MW GE 7FA.03 simple-cycle combustion turbine (CT-1) at the facility. The turbines utilize good combustion, operation, and maintenance practices and use of pipeline quality natural gas as control methods. CT-1 was added in a PSD permit dated April 7, 2000 and last amended on September 30, 2013. A modified PSD permit was issued on July 30, 2018. As a part of the modified PSD permit, emission limits for FPM and TPM_{10}/$TPM_{2.5}$ were increased to 0.00513 lb/MMBtu and 0.00686 lb/MMBtu, respectively.
Waverly Facility	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	15.0 (TPM, TPM_{10}, and $TPM_{2.5}$)	lb/hr	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The turbines utilize inlet air filtration as a control method. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging.

Facility Name	State	Permit Issuance	System Size	Turbine Model	PM Emission Limit [1]	Units [1]	Notes
Waverly Power Plant	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	15.09 (TPM, TPM_{10}, and $TPM_{2.5}$)	lb/hr	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The turbines utilize inlet air filtration as a control method. Emission limitation does not include periods of startup or shutdown. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.
Cameron LNG Facility	LA	2/17/2017	1,069 MMBtu/hr Heat Input for Each Turbine	Unknown	0.0076 (TPM_{10} and $TPM_{2.5}$)	lb/MMBtu	Gas turbines which utilize good combustion practices and natural gas fuel as control methods.
Mustang Station	TX	8/16/2017	163 MW	GE 7FA	27.0 (18.0 lb/hr) (TPM, TPM_{10} and $TPM_{2.5}$)	ton/yr	One 163 MW GE 7FA turbine (Unit No. 6) which was constructed in 2013 and utilizes good combustion practices and natural gas fuel as control methods. Permit involved increasing the turbine hours of operation to 3,000 hours per year.
Jackson County Generators	TX	1/26/2018	230 MW for Each Turbine	Unknown	11.81 (10.19 lb/hr) (TPM, TPM_{10} and $TPM_{2.5}$)	ton/yr	Four natural gas fired simple-cycle combustion turbines which utilize good combustion practices and natural gas fuel as control methods.
Ector County Energy Station [2]	TX	8/17/2020	Unknown	Unknown	-	-	Two simple-cycle gas turbines equipped with DLN burners for control. Firing of pipeline quality natural gas and good combustion practices is considered BACT for the turbines; a numeric emission limit was not established.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for PM associated with the turbine unit for natural gas firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for PM existed for the associated turbine units when firing natural gas. The established BACT limits for PM were added to this table.

The RBLC entries detailed in Table 5-8 includes potential modifications at facilities which were discussed in Section 5.6.6.1, with the addition of the Pueblo Airport Generating Station in Pueblo, Colorado. Many of the RBLC database entries have been conservatively included in Table 5-8 as they could not be ruled out as units proposed for construction based on information presented in the RBLC database entry alone. As was previously stated, further review of available air permits, permit applications, and other facility documentation proved that many of the turbine units associated with these RBLC database entries are not necessarily comparable to the WCP turbine units. This was also the case for the RBLC entry associated with the Pueblo Airport Generating Station, as the associated turbine unit for that RBLC entry is a GE LM6000 model turbine which is considered an aeroderivative turbine. Aeroderivative turbines have a much smaller power output than what would be expected from a large frame unit such as a GE Frame 7 turbine; therefore, the GE LM6000 PC turbines cannot be considered comparable units to reference for selection of BACT emission limits based on size.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems.

As was discussed in detail in Section 5.6.6.1, there are various factors as to why, even with the use of the same control technologies, the emission limits presented for the facilities in Table 5-8 are not necessarily directly comparable to the WCP units. Table 5-9 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-8 are comparable to the WPC units based on these factors.

Table 5-9. Unit Comparability for PM Assessment – Natural Gas Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	PM Emission Limit	Estimated lb/MMBtu
Cunningham Station Power Plant	Increase NO_X BACT Emission Limits	No, Westinghouse 501D5A	No	Not Comparable	
Calcasieu Plant [1]	Increase hours, heat input	Unknown	Yes	20.0 lb/hr (TPM_{10}/$TPM_{2.5}$)	0.0105 (TPM_{10} and $TPM_{2.5}$)
Emporia Energy Center – GE LM6000PC Units	N/A	No	No	Not Comparable	
Emporia Energy Center – GE 7FA	No (New in 2007) Added Tuning Requirements in 2013	Yes	No (New Unit) Yes (Engine Type)	18.0 lb/hr (TPM/TPM_{10})	0.0101 (TPM and TPM_{10})
Pueblo Airport Generating Station	N/A	No	No	Not Comparable	
Doswell Energy Center [2]	Turbine Relocation	Yes	Yes	0.00513 lb/MMBtu (9.0 lb/hr) (FPM) 0.00686 lb/MMBtu (12.0 lb/hr)	0.00513 (FPM) 0.00686 (TPM/TPM_{10}/$TPM_{2.5}$)

Site	Modification?	GE Frame 7 Turbine?	Comparable?	PM Emission Limit	Estimated lb/MMBtu
				(TPM/TPM$_{10}$/ TPM$_{2.5}$)	
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	15.0 lb/hr (TPM, TPM$_{10}$, TPM$_{2.5}$)	0.0095 (TPM, TPM$_{10}$, TPM$_{2.5}$)
Waverly Facility - 2018	Increase heat input	Yes	Potentially	15.09 lb/hr (TPM, TPM$_{10}$, TPM$_{2.5}$)	0.0075 (TPM, TPM$_{10}$, TPM$_{2.5}$)
Cameron LNG Facility	No – New	Compressor Turbines	No	Not Comparable	
Mustang Station	Increase hours	Yes, 2013 install	Potentially	27.0 ton/yr (18.0 lb/hr) (TPM/TPM$_{10}$/TPM$_{2.5}$)	Heat Input Capacity not determined
Jackson County Generators	No	No, Siemens F5	No	Not Comparable	
Ector County Energy Station	No (New in 2014), increased hours in 2020	Yes	Potentially	No Emission Limit Specified as BACT	

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed an emission limit for PM$_{10}$ of 17.0 lb/hr. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and established the emission limit for PM$_{10}$ as 20 lb/hr.

[2] PSD Permit issued on October 4, 2016 listed the emission limit for FPM and TPM$_{10}$/PM$_{2.5}$ as 0.00510 lb/MMBtu (10.0 lb/hr) and 0.00612 lb/MMBtu (12.0 lb/hr), respectively. A modified PSD permit was issued on July 30, 2018. As a part of the modified PSD permit, emission limits for FPM and TPM$_{10}$/TPM$_{2.5}$ were increased to 0.00513 lb/MMBtu (9.0 lb/hr) and 0.00686 lb/MMBtu (12.0 lb/hr), respectively.

For the units detailed in Table 5-9 that are potentially comparable to the modified WCP units, most limits for total PM$_{10}$/total PM$_{2.5}$ are specified in terms of lb/hr. As this mass emission rate is dependent on the size of the combustion turbine, a direct comparison in terms of lb/hr is not appropriate. To facilitate a limit comparison, where information was readily available, an equivalent lb/MMBtu has been estimated. Based on the available data, the range of BACT limits for TPM/TPM$_{10}$/TPM$_{2.5}$ when combusting natural gas is between 0.00686 – 0.0105 lb/MMBtu for units that are potentially comparable to the WCP turbines.

A historical review of information available for the WCP turbines when installed indicates a 19 lb/hr Total Suspended Particulate (TSP) and PM$_{10}$ guarantee. Given installation of the units in the early 2000s, these guarantees were likely intended to be filterable values based on Method 5 test methods. WCP, not the original site owners, does not have testing data related to the original turbine commissioning, nor has any recent PM related testing been conducted. When looking at the range of potential BACT limits (0.00686 – 0.0105 lb/MMBtu) and the heat input capacity of 1,766 MMBtu/hr for natural gas, the equivalent lb/hr rates would range from 12.1 – 18.5 lb/hr for total PM/PM$_{10}$/PM$_{2.5}$. As the highest lb/hr from the range for total PM is slightly less than the original manufacturer guarantee for filterable PM, WCP is proposing a BACT value that is higher than those summarized in Table 5-9.

If WCP relied on AP-42 for determining condensable emissions from the turbines 8.3 lb/hr of condensable PM would be estimated, leading to an estimated total PM/PM$_{10}$/PM$_{2.5}$ of 27.3 lb/hr (0.0155 lb/MMBtu) when combined with the filterable PM guarantee.[171] However, WCP recognizes there is likely some conservatism in both the original guarantee and the AP-42 factor. Given the challenges associated with accurate measurement of condensables, and the lack of available test data for the WCP turbines, **WCP is proposing a BACT emission limit for each turbine of 24.2 lb/hr for total PM/PM_{10}/$PM_{2.5}$, equivalent to an emission rate of 0.0137 lb/MMBtu.** Compliance with this BACT limit will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202 or alternative methods as appropriate.

5.7.6.2 Selection of Emission Limits for PM BACT – Fuel Oil Firing

Table 5-10 includes PM RBLC database entries for turbine units combusting fuel oil which may be potentially comparable to the existing units at the WCP facility.

[171] 1,766 MMBtu/hr (natural gas capacity) * 4.7E-3 lb condensables/MMBtu. Emission factor for Condensable PM is obtained from AP-42 Section 3.1, *Stationary Gas Turbines*, Table 3.1-2a (April 2000).

Table 5-10. Fuel Oil Simple-Cycle Combustion Turbine PM RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	PM Emission Limit [1]	Units [1]	Notes
Wolverine Power	MI	6/29/2011	540 MMBtu/hr Heat Input	Unknown	0.03 (16.2 lb/hr) (TPM_{10} and $TPM_{2.5}$)	lb/MMBtu	One ULSD fired turbine generator which will be used to start the plant when there is no power available from the electric grid and the plant must be brought back into service. Turbine utilizes good combustion control technology.
Waverly Facility [2]	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	39.0	lb/hr	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. Turbines utilize inlet air filtration for control of PM. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included.
Waverly Power Plant [2]	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	39.0	lb/hr	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. Turbines utilize inlet air filtration for control of PM. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for PM associated with the turbine unit for fuel oil firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for PM existed for the associated turbine units when firing fuel oil. The established BACT limits for PM were added to this table.

5.7.6.2.1 Summary – Fuel Oil PM BACT

The anticipated PM BACT for fuel oil firing will be good combustion practices and the use of ultra-low sulfur diesel. As was previously discussed, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-10 are not necessarily directly comparable to the WCP units. Table 5-11 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-10 are comparable to the WCP units based on these factors.

Table 5-11. Unit Comparability for PM Assessment – Fuel Oil Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	PM Emission Limit	Estimated lb/MMBtu
Wolverine Power	No – New	Unknown	No	Project Voided – Facility Was Not Built	
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	39.0 lb/hr (TPM, TPM_{10}, $TPM_{2.5}$)	0.0248 (TPM, TPM_{10}, $TPM_{2.5}$)
Waverly Facility - 2018	Increase heat input	Yes	Potentially	39.0 lb/hr (TPM, TPM_{10}, $TPM_{2.5}$)	0.0194 (TPM, TPM_{10}, $TPM_{2.5}$)

For the units detailed in Table 5-11 that are potentially comparable to the modified WCP units, the limits for total PM/PM_{10}/total $PM_{2.5}$ are specified in terms of lb/hr. As this mass emission rate is dependent on the size of the combustion turbine, a direct comparison in terms of lb/hr is not appropriate. To facilitate a limit comparison, where information was readily available, an equivalent lb/MMBtu has been estimated. Based on the available data, the range of BACT limits for TPM/TPM_{10}/$TPM_{2.5}$ when combusting fuel oil is between 0.0194 – 0.0248 lb/MMBtu for units that are potentially comparable to the WCP turbines.

Based on emissions information specific to turbines operated elsewhere by the owners of the WCP facility, **WCP proposes a BACT emission limit for each simple-cycle system of 26.8 lb/hr for filterable PM/total PM_{10}/$PM_{2.5}$, equivalent to an emission rate of 0.0142 lb/MMBtu.** Compliance with this BACT limit will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202 or alternative methods as appropriate.

5.7.6.3 Secondary BACT Limit – PM

Secondary BACT limits are not proposed as the particulate emissions of the combustion turbines are not considered to be dependent on control measures with varying effectiveness nor will they vary substantially in startup or shutdown modes.

5.8 Combustion Turbines CO Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for CO emissions from each combustion turbine. The following sections details the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for CO.

5.8.1 CO Formation – Combustion Turbines

CO from combustion turbines is a by-product of incomplete combustion. Conditions leading in incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion-temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to ensure NO_X emissions remain low may result in increased CO emissions.

5.8.2 Identification of CO Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

5.8.2.1 Oxidation Catalysts

An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form CO_2 and H_2O.

5.8.2.2 EM_X™ / $SCONO_X$™

EM_X™ (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, discussed in Section 5.6.2.4.

5.8.2.3 Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NO_X emissions. Accordingly, it is critical to optimize oxygen availability with input air, while controlling temperature to minimize NO_X formation.

5.8.3 Elimination of Technically Infeasible CO Control Options – Combustion Turbines (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

5.8.3.1 Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[172] Given the exhaust temperature of utility-scale simple-cycle combustion turbines is typically in excess of 1,000°F, use of oxidation catalyst could be considered technically infeasible, although the possibility of utilizing tempering air to reduce the inlet exhaust temperature, at substantial costs, exists. Therefore, oxidation catalyst is

[172] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

considered technically feasible for installation on the Facility's combustion turbines and will be considered further in Step 4 to evaluate cost effectiveness.

5.8.3.2 EM_X™/ $SCONO_X$™

The EM_X™/$SCONO_X$™ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_X, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[173] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[174]

Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of CO emissions from the WCP turbines.

5.8.3.3 Combustion Process Design and Good Combustion Practices

This represents the base case for design and operation of the simple-cycle combustion turbines.

5.8.4 Summary and Ranking of Remaining CO Controls – Combustion Turbines (Step 3)

As detailed in the Step 2 analysis for CO per Section 5.8.3, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it must be evaluated further in the BACT process.

5.8.5 Evaluation of Most Stringent CO Controls – Combustion Turbines (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling CO using oxidation catalyst for the WCP turbines is more than $28K per ton of CO removed based on the detailed cost analysis provided in Appendix D, developed using the methods outline by the U.S. EPA in the OAQPS guidance manual.[175] Similar to the technical challenges discussed for SCR for NO_X emissions reductions, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of an oxidation catalyst. Therefore, WCP concludes that an oxidation catalyst is not cost effective and is not considered BACT for the Facility's turbines

Therefore, combustion process design and good combustion practices represent BACT for the Facility's combustion turbines for CO.

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[173] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[174] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

[175] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf
For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

5.8.6 Selection of Emission Limits and Controls for CO BACT – Combustion Turbines (Step 5)

The simple-cycle combustion turbines are not presently subject to a CO emission limit and NSPS Subpart KKKK does not establish emission standards for CO. Accordingly, a BACT floor for CO does not exist.

As the selected BACT for CO emissions relies on the combustion process design and good combustion practices, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple-cycle combustion turbines are provided in the RBLC summary table in Appendix C. Review of the RBLC entries confirms that BACT for CO emissions are typically combustion process design and good combustion practices for similarly sized simple-cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C to identify potentially comparable units to the WCP turbines include:

For these RBLC entries, further research was conducted as needed using available permits, permit applications, and public documentation. The following qualifying criteria for potentially comparable units to the WCP turbines include:

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;
- Control method does not include control technologies which have been deemed to be infeasible (i.e., Oxidation Catalyst, EM_X™/$SCONO_X$™);
- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

5.8.6.1 Selection of Emission Limits for CO BACT - Natural Gas Firing

Table 5-12 includes CO RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility.

Table 5-12. Natural Gas Fired Simple-Cycle Combustion Turbine CO RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	CO Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Cunningham Power Plant [2]	NM	5/2/2011	Unknown	Unknown	77.2 and 138.9	lb/hr	-	Two simple-cycle combustion turbines equipped with DLN, capable of operating with or without power augmentation, and using good combustion practices as a control method. The turbines have specific CO limitations for each operating mode (emissions of CO are limited to 77.2 lb/hr without power augmentation and 138.9 lb/hr with power augmentation). CO emission limit excludes periods of startup and shutdown. Permit revises the NO_X BACT ppmvd limit for turbines established in previous PSD Permit No. PSD-NM-622-M2 because turbines have not been able to meet NO_X BACT limits.
Calcasieu Plant	LA	12/21/2011	1,900 MMBtu/hr Heat Input for Each Turbine	Unknown	15.0 (781.0 lb/hr)	ppmvd @ 15% O_2	Annual Avg.	Two simple-cycle combustion turbines of unknown make and model utilizing DLN combustors. CO emission limit excludes periods of startup and shutdown. PSD was triggered due to relaxation of a federally enforceable condition limiting potential emissions below major stationary source thresholds; subsequently revoked. PSD permit issued in 2015 lists the emission limitation for CO as 15.83 ppmvd @ 15% O_2.
Westar Energy – Emporia Energy Center	KS	3/18/2013	405 MMBtu/hr Heat Input for Each Turbine	GE LM6000 PC Sprint	63.8 @ temps. ≤ 54 °F 36.0 @ temps. > 54 °F	lb/hr	At full load	Four GE LM6000 PC Sprint natural gas fired simple-cycle turbines which are considered aeroderivative turbines. CO emission limit excludes periods of startup, shutdown, or malfunction. Turbines utilize efficient combustion/design technology for control of CO.
Westar Energy – Emporia Energy Center	KS	3/18/2013	1,780 MMBtu/hr Heat Input for Each Turbine	GE 7FA	39.0	lb/hr	At full load	Three GE 7FA natural gas fired simple-cycle turbines which utilize DLN burners for control. CO emission limit excludes periods of startup, shutdown, or malfunction. Turbines utilize efficient combustion/design technology for control of CO.
Doswell Energy Center	VA	10/4/2016	1,961 MMBtu/hr for Each Turbine	GE Frame 7FA	4.0 (0.00713 lb/MMBtu) (14.0 lb/hr)	ppmvd @ 15% O_2	3-hr Avg.	Authorization to add two 170 MW GE 7FA.03 natural gas fired, simple-cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center (DEC) equipped with DLN burners. Both CT-2 and CT-3 were proposed to be brought to DEC from an existing permitted site in Desoto, Florida and utilize pipeline quality natural gas as a control method. They are both similar in age and capability to the existing 190.5 MW GE 7FA.03 simple-cycle combustion turbine (CT-1) at the facility. CT-1 was added in a PSD permit dated April 7, 2000 and last amended on September 30, 2013. Emissions of CO exclude periods of startup, shutdown, and tuning.

Facility Name	State	Permit Issuance	System Size	Turbine Model	CO Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Waverly Facility	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	9.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of DLN burners when firing natural gas. Turbines utilize good combustion practices as a control method. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included.
Waverly Power Plant	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	9.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use of DLN burners when firing natural gas. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0028) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.
Cameron LNG Facility	LA	2/17/2017	1,069 MMBtu/hr Heat Input for Each Turbine	Unknown	15.0	ppmvd @ 15% O_2	1-hr Avg.	Gas turbines which utilize DLN burners and good combustion practices as control.
Mustang Station [2]	TX	8/16/2017	163 MW	GE 7FA	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	One 163 MW GE 7FA turbine (Unit No. 6) which was constructed in 2013 and utilizes DLN burners. Turbine uses good combustion practices as a control method. Permit involved increasing the turbine hours of operation to 3,000 hours per year. CO emission limit excludes periods of maintenance, startup, and shutdown.
Jackson County Generators	TX	1/26/2018	230 MW for Each Turbine	Unknown	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	Four natural gas fired simple-cycle combustion turbines which utilizes DLN burners for control. CO emission limit excludes periods of startup and shutdown.
Ector County Energy Station [2]	TX	8/17/2020	Unknown	Unknown	9.0	ppmvd @ 15% O_2	3-hr Rolling Avg.	Two simple-cycle gas turbines equipped with DLN burners which utilize good combustion practices as a control method. Emission limit for CO applies to normal operations.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for CO associated with the turbine unit for natural gas firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for CO existed for the associated turbine units when firing natural gas. The established BACT limits for CO were added to this table.

The RBLC entries detailed in Table 5-12 includes potential modifications at facilities which were discussed in Section 5.6.6.1. Many of the RBLC database entries have been conservatively included in Table 5-12 as they could not be ruled out as units proposed for construction based on information presented in the RBLC database entry alone. As was previously stated, further review of available air permits, permit applications, and other facility documentation proved that many of the turbine units associated with these RBLC database entries are not comparable to the WCP turbine units.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. WCP will continue to utilize those controls as BACT when firing natural gas in the turbines.

As was discussed in detail in Section 5.6.6.1, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-12 are not necessarily directly comparable to the WCP units. Table 5-13 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-12 are comparable to the WPC units based on these factors.

Table 5-13. Unit Comparability for CO Assessment – Natural Gas Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	CO Emission Limit	Averaging Period
Cunningham Station Power Plant	Increase NO_X BACT Emission Limits	No, Westinghouse 501D5A	No	Not Comparable	
Calcasieu Plant [1]	Increase hours, heat input	Unknown	Yes	15.83 ppmvd @ 15% O_2	Annual Avg.
Emporia Energy Center – GE LM6000PC Units	N/A	No	No	Not Comparable	
Emporia Energy Center – GE 7FA	No (New in 2007) Added Tuning Requirements in 2013	Yes	No (New Unit) Yes (Engine Type)	39 lb/hr	Stack test for compliance at full load
Doswell Energy Center	Turbine Relocation	Yes	Yes	4.0 ppmvd @ 15% O_2 (0.00713 lb/MMBtu) (14.0 lb/hr)	3-hr Avg.(2016) 1-hr Avg (2018)
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	9 ppm @loads 60% or higher	30-day Rolling Avg.
Waverly Facility - 2018	Increase heat input	Yes	Potentially	9 ppm @loads 60% or higher	30-day Rolling Avg.
Cameron LNG Facility	No – New	Compressor Turbines	No	Not Comparable	
Mustang Station	Increase hours	Yes, 2013 install	Potentially	9.0 ppmvd @ 15% O_2	3-hr Rolling Avg.

Site	Modification?	GE Frame 7 Turbine?	Comparable?	CO Emission Limit	Averaging Period
Jackson County Generators	No	No, Siemens F5	No	Not Comparable	
Ector County Energy Center	No (New in 2014), increased hours in 2020	Yes	Potentially	9.0 ppmvd @ 15% O_2	3-hr Rolling Avg.

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed a BACT limit for CO of 15.0 ppmvd @ 15% O_2. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and established the BACT limit for CO as 15.83 ppmvd @ 15% O_2.

As detailed in Table 5-13, potentially comparable engines combusting natural gas have CO emission limits ranging from 4.0 – 15.83 ppmvd at 15% O_2. Multiple units are subject to a 9 ppm CO limit, which is equivalent to GE's guarantee for the WCP turbines when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas. Although the lowest BACT limit for CO identified in Table 5-13 is 4.0 ppmvd at 15% O_2 based on a one hour averaging period, WCP does not anticipate that the existing turbine units at the facility are capable of achieving this rate. **WCP proposes a BACT limit for CO of 9 ppmvd at 15% O_2 on a 3-hr averaging basis when firing natural gas, excluding periods of startup and shutdown.** WCP anticipates conducting performance testing to document continuous compliance with the proposed CO BACT limit using a 3-hr averaging period.

5.8.6.2 Selection of Emission Limits for CO BACT – Fuel Oil Firing

Table 5-14 includes a CO RBLC database entry for turbine units combusting fuel oil which are potentially comparable to the existing units at the WCP facility.

Table 5-14. Fuel Oil Simple-Cycle Combustion Turbine CO RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	CO Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Wolverine Power	MI	6/29/2011	540 MMBtu/hr Heat Input	Unknown	0.045	lb/MMBtu	Test protocol will specify avg. time	One ULSD fired turbine generator which will be used to start the plant when there is no power available from the electric grid and the plant must be brought back into service. Turbine utilizes good combustion control technology.
Waverly Facility [2]	WV	1/23/2017	1,571 MMBtu/hr for Each Turbine	GE 7FA	20.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use good combustion practices as a control method. In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included.
Waverly Power Plant [2]	WV	3/13/2018	167.8 MW with 2,013 MMBtu/hr Heat Input for Each Turbine	GE 7FA.004	20.0	ppm @ loads of 60% or higher	30-day Rolling Avg.	Two GE Model 7FA turbines which are capable of combusting natural gas and firing fuel oil as back-up. The combustion turbines employ the use good combustion practices as a control method. Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for CO associated with the turbine unit for fuel oil firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for CO existed for the associated turbine units when firing fuel oil. The established BACT limits for CO were added to this table.

5.8.6.2.1 Summary Fuel Oil CO BACT

The anticipated BACT for CO when firing fuel oil would be combustion process design and good combustion practices. Table 5-15 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-14 are comparable to the WCP units based on these factors.

Table 5-15. Unit Comparability for CO Assessment – Fuel Oil Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	CO Emission Limit	Averaging Period
Wolverine Power	No – New	Unknown	No	Project Voided – Facility Was Not Built	
Waverly Facility - 2017	Relaxed synthetic minor limits	Yes	Potentially	20 ppmvd	30-day Rolling Avg.
Waverly Facility - 2018	Increase heat input	Yes	Potentially	20 ppmvd	30-day Rolling Avg.

As can be noted in Table 5-15, the potentially comparable turbine units are subject to CO limits of 20 ppm at 15% O_2. This limit is also consistent with the BACT limitation for CO of 20 ppmvd at 15% O_2 on a rolling 3-hour averaging basis for the Hill County Generating Facility which can be referenced in Appendix C. Although the turbine units at the Hill County Generating Facility are proposed for construction and therefore cannot necessarily be considered directly comparable to the WCP turbine units, it is worth noting the similarities between the CO BACT limitations for the newer state-of-the-art turbines proposed at that facility and the CO BACT limitations for the potentially comparable units in Table 5-15. As such, **WCP proposes a CO BACT emission limit for each simple-cycle system of 20 ppmvd at 15% O_2 on a 3-hr averaging basis when firing fuel oil, excluding periods of startup and shutdown.** WCP anticipates conducting performance testing to document continuous compliance with the proposed CO BACT limit using a 3-hr averaging period.

5.8.6.3 Secondary BACT Limit – CO

The proposed primary BACT limits of 9.0 ppmvd and 20 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different CO emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. WCP therefore proposes a secondary CO BACT limit per turbine of 70.9 tpy to ensure the minimization of emissions during startup/shutdown periods.

5.9 Combustion Turbines VOC Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for VOC emissions from each combustion turbine. The following sections details the “top down” BACT review, as well as the control technology and emission limits that are selected as BACT for VOC.

5.9.1 VOC Formation – Combustion Turbines

VOC from combustion turbines is a by-product of incomplete combustion. Conditions leading to incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion-temperature, reduced combustion gas residence time, and load reduction.

5.9.2 Identification of VOC Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

5.9.2.1 Oxidation Catalysts

An oxidation catalyst is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed prompting the VOC to react with oxygen present in the exhaust stream, converting to carbon dioxide and water vapor. The overall control efficiency of such systems on VOC constituents is dependent on the individual VOC components. For example, research completed by U.S. EPA as part of MACT rulemakings found that control of formaldehyde emissions typically exceed 90%, but other pollutants such as benzene may not see any beneficial reductions. Hence, the overall range of VOC control can vary substantially.[176]

5.9.2.2 EM_X^{TM} / $SCONO_X^{TM}$

EM_X^{TM} (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X and CO, as well as VOC without a reagent, discussed in Section 5.6.2.4.

5.9.2.3 Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of VOC, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Proper operation and good combustion practices provide additional VOC control via the use of gaseous fuels for good mixing and proper combustion techniques such as optimizing the air to fuel ratio.

5.9.3 Elimination of Technically Infeasible VOC Control Options – Combustion Turbines (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

5.9.3.1 Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[177] Given the exhaust temperature of utility-scale simple-cycle combustion turbines is typically in excess of 1,000°F, use of

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[176] U.S. EPA Office of Air Quality Planning and Standards Memorandum, *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines,* August 21, 2001.

[177] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

oxidation catalyst could be considered technically infeasible, although the possibility of utilizing tempering air to reduce the inlet exhaust temperature, at substantial costs, exists. Therefore, oxidation catalyst is considered technically feasible for installation on the Facility's combustion turbines and will be considered further in Step 4 to evaluate cost effectiveness.

5.9.3.2 EM_X™ / $SCONO_X$™

The EM_X™/$SCONO_X$™ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of NO_X, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM_X™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[178] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[179]

Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of VOC emissions from the WCP turbines.

5.9.3.3 Combustion Process Design and Good Combustion Practices

This represents the base case for design and operation of the simple-cycle combustion turbines.

5.9.4 Summary and Ranking of Remaining VOC Controls – Combustion Turbines (Step 3)

As detailed in the Step 2 analysis for VOC per Section 5.9.3, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it must be evaluated further in the BACT process.

5.9.5 Evaluation of Most Stringent VOC Controls – Combustion Turbines (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling VOC using oxidation catalyst for the WCP turbines is more than $32K per ton of VOC removed based on the detailed cost analysis provided in Appendix D, developed using the methods outline by the U.S. EPA in the OAQPS guidance manual.[180] Similar to the technical challenges discussed for SCR for NO_X emissions reductions and use of an oxidation catalyst system for CO emission reductions, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of an oxidation catalyst. Therefore, WCP concludes that an oxidation catalyst is not cost effective and is not considered BACT for the Facility's turbines

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[178] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[179] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU NO_X Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

[180] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf
For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Therefore, combustion process design and good combustion practices represent BACT for the Facility's combustion turbines for VOC.

5.9.6 Selection of Emission Limits and Controls for VOC BACT – Combustion Turbines (Step 5)

The simple-cycle combustion turbines are not presently subject to a VOC emission limit and NSPS Subpart KKKK does not establish emission standards for VOC. Accordingly, a BACT floor for VOC does not exist.

As the selected BACT for VOC emissions relies on the combustion process design and good combustion practices, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple-cycle combustion turbines are provided in the RBLC summary table in Appendix C. Review of the RBLC entries confirms that BACT for VOC emissions are typically combustion process design and good combustion practices for similarly sized simple-cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C to identify potentially comparable units to the WCP turbines:

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;
- Control method does not include control technologies which have been deemed to be infeasible (i.e., Oxidation Catalyst, EM_X™/$SCONO_X$™);
- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

5.9.6.1 Selection of Emission Limits for VOC BACT - Natural Gas Firing

Table 5-16 includes VOC RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility.

Table 5-16. Natural Gas Fired Simple-Cycle Combustion Turbine VOC RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	VOC Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Calcasieu Plant	LA	12/21/2011	1,900 MMBtu/hr Heat Input for Each Turbine	Unknown	3.0	ppmvd @ 15% O_2	-.	Two simple-cycle combustion turbines of unknown make and model utilizing DLN combustors. VOC emission limit excludes periods of startup and shutdown. PSD was triggered due to relaxation of a federally enforceable condition limiting potential emissions below major stationary source thresholds; subsequently revoked. According to the PSD permit issued in 2015, emissions of VOC were not above PSD modification thresholds.
Westar Energy – Emporia Energy Center	KS	3/18/2013	405 MMBtu/hr Heat Input for Each Turbine	GE LM6000 PC Sprint	5.8	lb/hr	At full load	Four GE LM6000 PC Sprint natural gas fired simple-cycle turbines which are considered aeroderivative turbines. VOC emission limit excludes periods of startup, shutdown, or malfunction. Turbines utilize efficient combustion/design technology for control of VOC.
Westar Energy – Emporia Energy Center	KS	3/18/2013	1,780 MMBtu/hr Heat Input for Each Turbine	GE 7FA	3.2	lb/hr	At full load	Three GE 7FA natural gas fired simple-cycle turbines which utilize DLN burners for control. VOC emission limit excludes periods of startup, shutdown, or malfunction. Turbines utilize efficient combustion/design technology for control of VOC.
Doswell Energy Center [2]	VA	10/4/2016	1,961 MMBtu/hr for Each Turbine	GE Frame 7FA	3.57E-04 (0.7 lb/hr)	lb/MMBtu	-	Authorization to add two 170 MW GE 7FA.03 natural gas fired, simple-cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center (DEC) equipped with low NO_X burners. Both CT-2 and CT-3 were proposed to be brought to DEC from an existing permitted site in Desoto, Florida. They are both similar in age and capability to the existing 190.5 MW GE 7FA.03 simple-cycle combustion turbine (CT-1) at the facility. The turbines utilize good combustion practices as a control method. CT-1 was added in a PSD permit dated April 7, 2000 and last amended on September 30, 2013. Permit issued on May 31, 2018 updated the VOC emission limit for CT-2 and CT-3 to 2 ppmvd @ 15% O_2 (3.3 lb/hr) on a 1-hr averaging basis.
Puente Power	CA	10/13/2016	262 MW	Unknown	2.0	ppmvd @ 15% O_2 as methane	1-hr Avg.	One 262 MW gas turbine.
Cameron LNG Facility	LA	2/17/2017	1,069 MMBtu/hr Heat Input for Each Turbine	Unknown	1.6	ppmvd @ 15% O_2	3-hr Avg.	Gas turbines which utilize DLN burners and good combustion practices as control.
Mustang Station [2]	TX	8/16/2017	163 MW	GE 7FA	2.0	ppmvd @ 15% O_2	-	One 163 MW GE 7FA turbine (Unit No. 6) which was constructed in 2013 and utilizes DLN burners. Turbine uses good combustion practices as a control method. Permit involved increasing the turbine hours of operation to 3,000 hours per year.
Jackson County Generators	TX	1/26/2018	230 MW for Each Turbine	Unknown	2.0	ppmvd @ 15% O_2	-	Four natural gas fired simple-cycle combustion turbines which utilizes DLN burners and good combustion practices as control methods.

Facility Name	State	Permit Issuance	System Size	Turbine Model	VOC Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Ector County Energy Station [2]	TX	8/17/2020	Unknown	Unknown	2.0	ppmvd @ 15% O_2	-	Two simple-cycle gas turbines equipped with DLN burners for control. Turbine uses good combustion practices as a control method.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for VOC associated with the turbine unit for natural gas firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for VOC existed for the associated turbine units when firing natural gas. The established BACT limits for VOC were added to this table.

The RBLC entries detailed in Table 5-16 includes potential modifications at facilities which were discussed in Section 5.6.6.1. Many of the RBLC database entries have been conservatively included in Table 5-16 as they could not be ruled out as units proposed for construction based on information presented in the RBLC database entry alone. As was previously stated, further review of available air permits, permit applications, and other facility documentation proved that many of the turbine units associated with these RBLC database entries are not comparable to the WCP turbine units.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for VOC BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. WCP will continue to utilize those controls as BACT when firing natural gas in the turbines.

As was discussed in detail in Section 5.6.6.1, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-16 are not necessarily directly comparable to the WCP units. Table 5-17 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-16 are comparable to the WPC units based on these factors.

Table 5-17. Unit Comparability for VOC Assessment – Natural Gas Firing

Site	Modification?	GE Frame 7 Turbine?	Comparable?	VOC Emission Limit	Averaging Period
Calcasieu Plant [1]	Increase hours, heat input	Unknown	Yes	N/A – Did not exceed PSD threshold per 2015 PSD permit; ultimately revoked	
Emporia Energy Center – GE LM6000PC Units	N/A	No	No	Not Comparable	
Emporia Energy Center – GE 7FA	No (New in 2007) Added Tuning Requirements in 2013	Yes	No (New Unit) Yes (Engine Type)	3.2 lb/hr (0.0018 lb/MMBtu)	Stack test for compliance at full load
Doswell Energy Center [2]	Turbine Relocation	Yes	Yes	2 ppmvd @ 15% O_2	1-hr Avg.
Puente Power	No - New	Yes	No	Application Revoked	
Cameron LNG Facility	No – New	Compressor Turbines	No	Not Comparable	
Mustang Station	Increase hours	Yes, 2013 install	Potentially	2 ppmvd @ 15% O_2	-
Jackson County Generators	No	No, Siemens F5	No	Not Comparable	

Site	Modification?	GE Frame 7 Turbine?	Comparable?	VOC Emission Limit	Averaging Period
Ector County Energy Center	No (New in 2014), increased hours in 2020	Yes	Potentially	2 ppmvd @ 15% O_2	-

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed a BACT limit for VOC of 3.0 ppmvd @ 15% O_2. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and determined that emissions of VOC were not above PSD significant levels; therefore, BACT is not applicable for VOC for the Calcasieu Plant.

[2] The PSD permit for the Doswell Energy Center issued on October 4, 2016 incorporated a VOC BACT limit of 3.57E-04 lb/MMBtu (0.7 lb/hr) for the natural gas fired simple-cycle turbines (CT-2 and CT-3). However, per a revised PSD Permit issued on May 31, 2018, the VOC BACT limit was updated to 2 ppmvd @ 15% O2 (3.3 lb/hr) on a 1-hr averaging basis. This is also consistent with the PSD permit issued on July 30, 2018.

As detailed in Table 5-17, potentially comparable engines combusting natural gas have VOC limits of 3.2 lb/hr, equivalent to 0.0018 lb/MMBtu and 2 ppmvd @ 15% O_2. GE's guarantee for the WCP turbines when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas is 1.4 ppmvd at 15% 0_2; equivalent to 0.00446 lb/MMBtu. Additional research identified a Texas BACT document establishing 2.0 ppmvd as BACT for simple-cycle natural gas combustion turbines.[181] For compliance assurance purposes, **WCP therefore proposes a BACT limit of 2.0 ppmvd at 15% O_2, excluding periods of startup and shutdown,** to be demonstrated via stack testing.[182].

5.9.6.2 Selection of Emission Limits for VOC BACT – Fuel Oil Firing

Table 5-18 includes VOC RBLC database entries for turbine units combusting fuel oil which may be potentially comparable to the existing units at the WCP facility.

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[181] Summary spreadsheet *Current BACT for All Combustion Units*, accessed January 27, 2021. https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact-combustion.xlsx

[182] Method 25A for the determination of volatile organic compounds.

Table 5-18. Fuel Oil Fired Simple-Cycle Combustion Turbine VOC RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	System Size	Turbine Model	VOC Emission Limit [1]	Units [1]	Averaging Period [1]	Notes
Wolverine Power [2]	MI	6/29/2011	540 MMBtu/hr Heat Input	Unknown	-	-	-	One ULSD fired turbine generator which will be used to start the plant when there is no power available from the electric grid and the plant must be brought back into service. Turbine utilizes good combustion control technology.

[1] Please note that the Emission Limit and Averaging Periods for each RBLC entry was cross referenced with the associated air permit for each entry, as available. Corrections were made as necessary, to ensure that emission limits and averaging periods were consistent with the air permits associated with each RBLC entry.

[2] Facility did not have a RBLC database entry for VOC associated with the turbine unit for fuel oil firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for VOC existed for the associated turbine units when firing fuel oil. The established BACT limits for VOC were added to this table.

As can be referenced in Table 5-18, Wolverine Power is the only facility with turbine units which are potentially comparable to the WCP units. However, the turbines at the Wolverine Power facility are not subject to a BACT limit for VOC, but rather must comply by utilizing good combustion control technology to mitigate emissions of VOC. Furthermore, as was stated in Section 5.6.6.2.1, plans for the Wolverine Power project were discontinued in 2013 and the facility was never built.

The anticipated BACT for VOC when firing fuel oil would be combustion process design and good combustion practices. Based on BACT limitations for VOC at a similar facility which incorporates the use of dual-fuel fired turbine units, **WCP proposes a BACT limit for VOC of 5.0 ppmvd at 15% O_2, excluding periods of startup and shutdown,** with compliance demonstrated via stack testing.[183]

5.10 Fuel Oil Storage Tank VOC Assessment

WCP is proposing to construct and operate a new vertical fixed roof tank which will store fuel oil and have a capacity of 2.5 million gallons. Annual emissions resulting from the storage tank have been estimated in Appendix B and are not expected to exceed 0.66 tons per year. Given the low magnitude of emissions from the proposed fuel oil storage tank, WCP proposes that the tank be subject to work practice and design standards in lieu of an emission limitation.

Due to the low vapor pressure of fuel oil and minimal estimated annual emissions from the proposed storage tank, a vapor collection and control device for control of emissions will not be utilized. Additionally, carbon adsorption systems are generally not effective for control of low concentrations of VOC which would be generated by a diesel storage tank. The use of floating roofs are also not considered effective for controlling VOC emissions from liquids having low vapor pressures such as diesel.[184] Given the capital costs involved with installation of add-on controls for reduction of less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective.

For this small source of VOC emissions, WCP is proposing to incorporate the use of submerged fill systems in the fuel oil storage tank to minimize emissions of VOC resulting from splashing of product loaded. A fill pipe opening will be submerged below the tank's liquid surface level, thereby ensuring that liquid turbulence is mitigated during loading, resulting in minimal emissions into the vapor space above the liquid surface. Another method which WCP will utilize to control emissions from the fuel oil storage tank is to minimize product temperature via the use of light-colored paint for the tank shell and roof. Evaporative losses can be minimized significantly via the appropriate condition and color selection of a storage tank's shell and roof. Evaporative losses have a strong relationship with temperature of liquid product stored; therefore, reducing liquid product temperature can minimize evaporative losses. Solar radiation will increase the temperature of the liquid in a storage tank, but the extent of the temperature increase is determined by the color and condition of the paint on the tank walls and roof. Paints having a low solar absorptance (i.e., light colored tanks) will heat up less than paints with high solar absorptance (i.e., dark colored tanks). White paint, for

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[183] Part 70 Operating Permit Amendment No. 4911-157-0034-V-04-1 issued by Georgia EPD for the Dahlberg Combustion Turbine Electric Generating Plant, effective May 14, 2010. Amendment resulted from a PSD permit application for installation of four simple cycle dual-fuel combustion turbines.

[184] *Preliminary Determination & Statement of Basis – Outer Continental Shelf Air Permit Modification OCS-EPA-R4012-M1 for Statoil Gulf Services, LLC – Desota Canyon Lease Blocks*, issued by the U.S. EPA Region 4 on July 9, 2014. Discussion related to BACT analysis for storage tanks, Section 6.5 page 29.

example, is highly reflective and typically used to minimize the tank's ambient temperature, which, in turn, reduces standing losses.[185]

WCP has determined that BACT for the proposed fuel oil storage tank will be the use of good maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and selection of tank roof and shell paint colors which have low solar absorptance.

5.11 Combustion Turbines GHG Assessment

This section contains a high-level review of pollutant formation and possible control technologies for the combustion turbine systems. Though the primary GHG emissions from natural gas and fuel oil combustion in the combustion turbine systems are CO_2, GHG BACT is discussed separately for CH_4 and N_2O.

CO_2 production from combustion occurs in theory by a reaction between carbon in any fuel and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[186] CH_4 can be emitted when natural gas and fuel oil are not burned completely in combustion.[187] The last primary component for calculating greenhouse gas emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete gas and oil combustion situations, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[188]

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of BACT for CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a simultaneous increase in emissions of another GHG (i.e., CO_2).

5.11.1 Turbine Systems CO_2 BACT

The following section presents BACT evaluations for CO_2 emissions from the modified turbine systems.

5.11.1.1 Identification of Potential CO_2 Control Technologies (Step 1)

WCP searched for potentially applicable emission control technologies for CO_2 from combustion turbines by researching the U.S. EPA control technology database, guidance from U.S. EPA and other sources as described in Section 5.4.1 of this report, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are summarized in Appendix C, detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHGs were described for any of

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[185] Eric Stricklin. "Evaporative Losses From Storage Tanks," Chesapeake Operating, Inc. http://technokontrol.com/pdf/evaporation/evaporation-loss-measurement.pdf. (accessed January 26, 2021).

[186] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[187] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998. Chapter 1, Section 3, *Fuel Oil Combustion*. July 1998.

[188] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

the facilities. Many facilities listed a variant of good combustion practices, efficient operation, state-of-the-art technology (for greenfield sites), or low emitting fuels (e.g., pipeline-quality natural gas). Although not mentioned in the RBLC for any sites, energy storage technologies such as batteries are deemed to fall outside the scope of this analysis since they would essentially redefine the source.

WCP used a combination of published resources and general knowledge of industry practices to generate a list of potential controls for CO_2 emitted from combustion turbine systems. WCP excluded options such as battery storage or solar power generation from the GHG control technology assessment as they would redefine the business purpose of the proposed projects: WCP Sandersville proposes to operate as a natural gas and fuel oil-fired electric generating facility utilizing simple-cycle combustion turbines, maximizing utilization of the existing assets in a relatively steady-state mode of operation, with normal anticipated variations based on supply needs. U.S. EPA has affirmed that evaluation of control options or lower-emitting GHG processes, such as solar power, that would fundamentally redefine the source is not a requirement of the BACT review in their response to comments on the proposed Palmdale Hybrid Power Project, subsequently upheld in an order denying review of the PSD permit.[189]

The following potential CO_2 control strategies were considered as part of this BACT analysis:

- Carbon Capture and Storage (CCS); and
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices.

These control technologies are briefly discussed in the following sections. Other CO_2 control technologies such as use of alternative fuels (with lower GHG emissions) were not considered because they were not within the scope of the projects. Additionally, natural gas (which has the lowest GHG emissions of any fossil fuel) is the primary fuel that will be utilized by the turbines, with fuel oil usage being limited to 500 hr/yr.

5.11.1.1.1 Carbon Capture and Storage

CCS, also known as CO_2 sequestration, involves cooling, separation and capture of CO_2 emissions from the flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage.

The first phase in CCS is to separate and capture the CO_2 gas from the exhaust stream, and then to compress the CO_2 to a supercritical condition.[190] Since most storage locations for CO_2 are greater than 800

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[189] U.S. EPA Environmental Appeals Board decision, *In re: City of Palmdale (Palmdale Hybrid Power Project)*. PSD Appeal No. 11-07, p. 727, decided September 17, 2012, citing .S. EPA Region 9, *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project* at 3 (Oct. 2011).

"Finally, we [EPA] note that the incorporation of the solar power generation into the BACT analysis for this facility [Palmdale] does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project."

[190] Supercritical means that the CO_2 has properties of both a liquid and a gas. Supercritical CO_2 is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

meters deep, where the natural temperatures and pressures are greater than the critical point for CO_2, to inject CO_2 to those depths requires pressurizing the captured CO_2 to a supercritical state.

CO_2 capture can be performed via solvents or sorbents. The choice of the precise process varies with the properties of the exhaust stream. CO_2 separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a turbine system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated CO_2 than exhaust from natural gas and fuel oil combustion, or on natural gas combined-cycle systems. Existing CO_2 capture technologies have not been demonstrated in the context of capturing CO_2 from simple-cycle combustion turbines, regardless of industry use, as they have higher exit gas temperatures and lower cycle efficiencies, which negatively affects the ability of the CCS systems to control CO_2 emissions.[191]

Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. There are no technical challenges with compressing CO_2 to those levels, but specialized technologies with high operating energy requirements are necessary. The CO_2 could be compressed to supercritical either before or after transport.

For phase two, CO_2 would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO_2 pipelines, particularly if supercritical CO_2 is being transported. Transport of CO_2 by pipeline is a demonstrated technology, but currently most CO_2 pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various CO_2 storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting CO_2 into deep subsurface formations for long-term storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO_2 could also potentially be used for enhanced oil recovery via injection into oil fields.

5.11.1.1.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine operation and good combustion, operating, and maintenance practices. One example of an efficient way to generate electricity from a natural gas and fuel oil-fired source is the use of a combined cycle design.[192]

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance by abiding by an operations and maintenance (O&M) plan. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

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[191] *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, US Department of Energy. accessed January 2021. https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf

[192] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

5.11.1.2 Elimination of Technically Infeasible CO_2 Control Options – Turbine Systems (Step 2)

5.11.1.2.1 Carbon Capture and Storage

CCS involves cooling, separation and capture of CO_2 from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

It should be noted that there is little to no research that has been completed on the implementation of CCS systems on simple cycle turbines, nor on turbines that utilize fuel oil. Though the lack of research is due to general industry understanding that it is impossible to utilize a CCS system on a simple cycle turbine, the technical feasibility is still conservatively examined in this section. However, due to this lack of research on simple cycle or fuel-oil fired turbines, the technical feasibility in this section is completed using data collected on CCS systems installed on natural gas combined cycle turbines.

<u>Carbon Capture</u>

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[193] Currently, only two options appear to be feasible for capture of CO_2 from the flue gas from the turbine systems: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[194]

A review of the U.S. Department of Energy's (DoE) National Energy Laboratory's (NETL) research and development awards related to post-combustion capture of CO_2 indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus.[195] For example, an ongoing project focused on implementation of a membrane capture process at Basin Electric's Dry Fork Station in Wyoming details pilot scale testing completed related to membranes and outlines the study parameters to develop a path to commericialization for a coal-fired utility.[196] Note that the economic feasibility of membrane-technology is presently being studied with regard to retrofitting an existing natural gas combined-cycle combustion turbine operation, Elk Hills Power Plant, located in the middle of the Elk Hills Oil

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[193] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[194] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[195] Website reviewed January 2021: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[196] *Commerical-Scale Front-End Engineering Design Study for Membrane Technology and Research's Membrane Carbon Dioxide Capture Process,* U.S. Department of Energy, National Energy Technology Laboratory, Fact Sheet for Project Number FE0031846, start date October 1, 2019.

https://netl.doe.gov/projects/plp-download.aspx?id=20071&filename=FE0031846_MTR_Polaris%20FEED_tech%20sheet.pdf

Field, providing options for carbon storage as well as for enhanced oil recovery.[197] Review of the DoE's research projects do not indicate any activity related to fuel oil combustion sources.[198] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character to the flue gas from the turbine systems, to WCP's knowledge, the technology has never been commercially demonstrated for flue gas control in natural gas fired turbine operations.[199]

Presuming carbon capture is feasible, prior to sending the CO_2 stream to the appropriate storage site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[200] The auxiliary power load could be handled by installation of a separate system to solely support CO_2 compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an "energy penalty" for operation of the CO_2 compression system.

Carbon Transport

The next step in CCS is the transport of the captured and compressed CO_2 to a suitable location for storage. This would typically be via pipeline. Pipeline transport is available and demonstrated, although costly, technology. Short CO_2 pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

Since there are no other CO_2 pipelines in the area, WCP would need to construct a CO_2 pipeline to a storage location if it were to pursue carbon sequestration as a CO_2 control option.[201] While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

Carbon Storage

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering

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[197] *Front-End Engineering Design Study for Retrofit Post-Combustion Carbine Capture on a Natural Gas Combined Cycle Power Plant,* U.S. Department of Energy, National Energy Technology Laboratory, Fact Sheet for Project Number FE0031842, start date October 1, 2019.

https://netl.doe.gov/projects/plp-download.aspx?id=20050&filename=FE0031842_EPRI%20FEED_tech%20sheet.pdf

[198] Website reviewed January 2021: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[199] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for GHG emissions, Attachment B page 62.

[200] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[201] *A Review of the CO_2 Pipeline Infrastructure in the U.S.*, National Energy Technology Laboratory, Office of Fossil Energy, U.S. Department of Energy, April 2015. DOE/NETL-2014/1681. https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rock.
- Un-Mineable Coal Seams: Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for WCP to permanently store the captured CO_2.

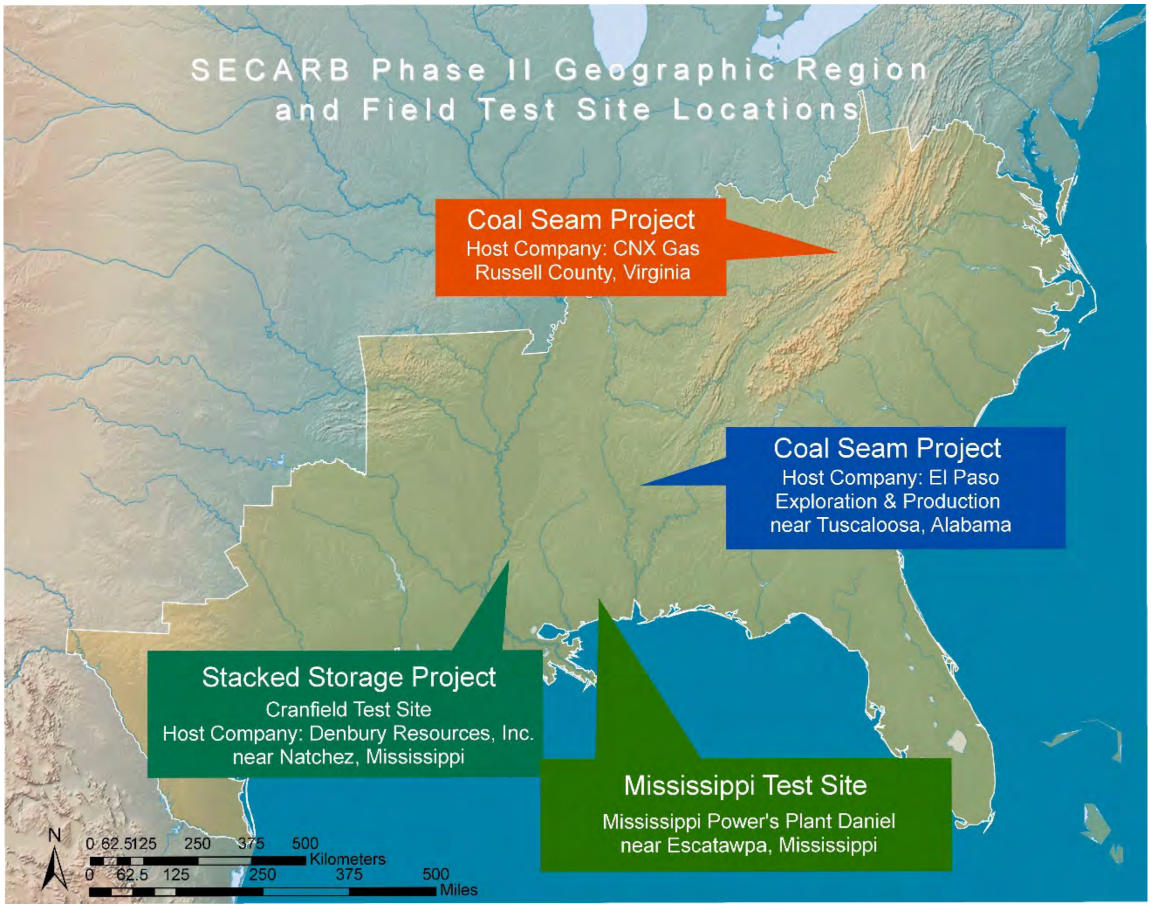
NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[202] According to the database, the Black Warrior Basin of Alabama is the closest sequestration site where a test well has been drilled. The Black Warrior Basin, located Northeast of Tuscaloosa, Alabama is a pilot-scale Southeast Regional Carbon Sequestration Partnership (SECARB) CO_2 sequestration project site that has achieved an injection of 278 tons of CO_2 with the potential to sequester 1.12 to 2.32 Gigatonnes (Gt) of CO_2.[203] The injection location is a mature coalbed methane reservoir within the Blue Creek Coal Degasification Field in Tuscaloosa County, Alabama. Figure 5-1 is a map of possible sequestration formations that have gone through SECARB's Phase II Validation program.[204] The Black Warrior Basin, listed as the Coal Seam Project near Tuscaloosa, AL on Figure 5-1, is the closest pilot or large-scale CO_2 sequestration project site to WCP Sandersville and is approximately 246 miles from the Facility.

[202] Carbon Capture and Storage Database maintained by the NETL, accessed January 2021 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[203] *Black Warrior Basin Coal Seam Project,* SECARB. Summary document at http://www.secarbon.org/files/black-warrior-basin.pdf

[204] http://www.secarbon.org/index.php?page_id=8

Figure 5-1. Map of Potential Carbon Sequestration Sites



WCP has concluded that CCS technology is not technically feasible at this time, based on the discussions provided. However, despite the significant technical challenges discussed earlier in implementing CCS technology on turbine systems of this size, WCP is including CCS in Step 3 of this analysis, although realistically technical feasibility is still unlikely.

5.11.1.2.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

One way to efficiently generate electricity from a natural gas or fuel oil fuel source is the use of a combined-cycle turbine design.[205] However, usage of combined-cycle technology is not feasible for this project, as it will remove the turbine's capability to perform its function as a quick starting unit. For the purposes of BACT consideration, combined-cycle and simple-cycle turbines are not considered to be the same source type. Therefore, the use of combined-cycle technology is not being considered as a way of increasing efficiency as it fundamentally changes the scope of the project, and will not be evaluated beyond this step. The EPA Environmental Appeals Board (EAB) affirmed the determination that simple-cycle and combined-cycle

[205] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

technologies are different source types for BACT determination in its response to comments on a PSD permit application for the Pio Pico Energy Center in August 2013.[206]

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.
Therefore, CCS and efficient turbine operation coupled with good combustion, operating, and maintenance practices are evaluated further for CO_2 BACT purposes.

5.11.1.3 Summary and Ranking of Remaining CO_2 Controls (Step 3)

The remaining control methods are listed below, in descending order of the expected CO_2 reductions.

- Carbon capture and storage (CCS), 90% reduction[207]
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices, reduction efficiency is not applicable.

5.11.1.4 Evaluation of Most Stringent CO_2 Control Technologies (Step 4)

5.11.1.4.1 Carbon Capture and Storage

As the most stringent control option available, CCS would be considered BACT, barring the consideration of its energy, environmental, and/or economic impacts. However, for the reasons outlined in this section, this option should not be relied upon as BACT and the next most stringent alternative should be evaluated.

The use of CCS would be prohibitive to the project, as the cost of installing and maintaining the system will greatly exceed the benefit of any GHG emission reductions the system will offer. The costs associated with the system include capital costs, such as the installation of a pipeline for conveyance and the actual installation of the system, and the operation and maintenance costs of carbon capture, transport, and storage. Detailed cost calculations are provided in Appendix D, with a brief summary herein.

The first capital cost for consideration is the cost associated with the installation of a pipeline from the Sandersville site to the nearest carbon sequestration site. Currently, there exist no carbon storage sites in the state of Georgia, and the site closest to Sandersville is the Black Warrior Basin located near Birmingham, Alabama. If the shortest possible pipeline between these sites were to be installed, 246 miles of pipeline

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[206] EAB responded to comments that BACT for a simple-cycle turbine should require a combined-cycle configuration as BACT. In the written response to the appeal, EAB wrote:

"*Mr. Simpson and Sierra Club have not demonstrated that the Region clearly erred in eliminating combined-cycle gas turbines in step 2 of its BACT analysis for greenhouse gases, or that the issue otherwise warrants review or remand. In particular, the Board concludes that the Region did not define "source type" too narrowly in step 2, nor did the Region clearly err when it referenced the power purchase agreement and relateddocuments in its analysis.*"

[207] *Estimating Carbon Dioxide Transport and Storage Costs*, National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Page 9, March 2010.

would be installed, crossing from Georgia into Alabama.[208] In addition, one injection well will need to be installed at the basin. Costs involved include an initial site screening, purchasing of injection equipment, well construction, and liability insurance.

As previously discussed, evaluation of costs for CCS systems for natural gas combustion have focused on combined-cycle units. Hence, for purposes of this evaluation, use of cost information related to a natural gas combined-cycle energy facility have been relied upon. Capital costs for carbon capture are calculated based on the difference between a natural gas combined-cycle energy facility with and without capture in terms of $/kW (net). Total plant capital cost for a turbine with no CCS capture is estimated as 780 $/kW, while total plant capital cost for a turbine with CCS is estimated as 1,984 $/kW.[209] As evidenced by these values, the cost of installing a system with CCS capture is greater than double the cost of installing one without. The estimated capital cost for installing the CCS system for the affected turbines by calculating the capital cost for each scenario and taking the difference to calculate the additional cost from the installation of the system.

When the aforementioned costs are summed, the total capital costs for installing a CCS system are greater than $1 billion. This cost alone is clearly prohibitive to the installation of the system but does not yet take operating and maintenance costs into account.

There are several costs related to the ongoing operation and maintenance of a CCS system that are not accounted for in the capital cost, including:

- Operating and maintenance costs for the CCS system such as labor, property taxes, and insurance, as well as costs to purchase the water and chemicals (including an MEA solvent) used in the system itself.
- The pipeline to transport the compressed gas to the storage site has a fixed operation and maintenance costs.[210]
- The actual storage of the gas at a chosen location requires pore space acquisition, daily expenses, consumables, surface maintenance, and subsurface maintenance.[211]

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[208] Distance from the facility to the nearest potential CO_2 sequestration facility (Black Warrior Basin) per the Southeast Regional Carbon Sequestration Partnership (SECARB), conservatively assuming the shortest distance as the pipeline route. Note that this site utilized an injection well as part of SECARB's Phase I study, but that injection well has reverted back to its original use for coalbed methane production.

http://secarbon.org/index.php?page_id=8; and

http://secarbon.org/files/black-warrior-basin.pdf

[209] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, September 2019, Exhibit 5-17, Case B31A Total Plant Cost Details (page 526) and Exhibit 5-31. Case B31B Total Plant Cost Details (page 545).

https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf

[210] *Carbon Dioxide Transport and Storage Costs in NETL Studies,* March 2013 DOE/NETL-2013/1614, Exhibit 2.

[211] *Estimating Carbon Dioxide Transport and Storage Costs*, March 2010 National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

http://www.canadiancleanpowercoalition.com/pdf/CTS11%20-%20QGESStransport.pdf

Based on the calculations completed for these costs, the total annualized cost for operation and maintenance of the CCS system will exceed $235 million. The resulting annualized total capital and operating cost per ton of CO_2 controlled is approximately $170 per ton.

The overall costs of installing and operating the CCS system are clearly prohibitive to completing the project, both in terms of absolute costs and cost effectiveness on a $/ton pollutant removed basis. Given the negative economic considerations, as well as the technical challenges associated with implementing CCS on a simple-cycle turbine, it is deemed infeasible and eliminated as a viable option for BACT.

5.11.1.5 Selection of CO_2 BACT (Step 5)

CO_2 BACT for these projects includes efficient turbine operation coupled with good combustion, operating, and maintenance practices. As mentioned previously, the resulting BACT standard is an emission limit unless technological or economical limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

BACT determinations for similar simple-cycle generating units, as detailed in the RBLC summary tables in Appendix C denote energy efficiency, good design and good combustion practices as BACT. Post-combustion capture and sequestration of CO_2 is not required. BACT limits for natural gas and fuel oil simple-cycle units can be found expressed in terms of lb/MWh, Btu/kWh, or tons, typically with a 12-month rolling total averaging period.

Due to the inherent intermittent usage of the turbine systems, it is most effective to set a BACT limit for tons of CO_2e emitted over a 12-month rolling total averaging period for the units at the WCP Sandersville facility. To calculate the BACT limit, emission factors for fuel combustion were based on U.S. EPA default fuel combustion emission factors found in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, converted from units of kg/MMBtu to lb/MMBtu.

The maximum annual operating capacity for each type of fuel was calculated based on the fuel input capacities for each fuel type. The natural gas heat input capacity per turbine is 1,766 MMBtu/hr. Presuming 3,000 hours per year on natural gas per turbine, the facility has a maximum annual operating capacity of 21.2 million MMBtu/yr from natural gas. The fuel oil heat input capacity per turbine is 1,890 MMBtu/hr. With 500 hours per year per turbine for fuel oil combustion, the facility has a maximum annual operating capacity of 3.8 million MMBtu/yr from fuel oil.

As detailed in Appendix C, multiplying the U.S. EPA emission factors by the maximum annual operating capacity for each type of fuel yields maximum potential emissions of 1,240,760 tons of CO_2e/year from natural gas combustion and 309,228 tons of CO_2e/year from fuel oil combustion. Summing these together yields potential CO_2e emissions of 1,549,988 tpy from the turbine systems combined. As such, WCP Sandersville is proposing a BACT limit of **387,497 tpy** of CO_2e on a 12-month rolling averaging period for each turbine unit.

Based on a review of the RBLC database, this BACT limit is comparable to other limits that have been established for facilities with similar systems in place. As such, WCP Sandersville believes it is appropriate to comply with PSD requirements.

Compliance with the proposed BACT limit will be demonstrated by monitoring fuel consumption. Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2, CH_4, and N_2O emission factors from 40 CFR Part 98 Subpart C, Tables C-1 and C-2, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO_2, 25 for CH_4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12-month rolling total tons per year emission limit is not exceeded.

Through this proposed BACT limit, WCP limits the maximum fuel consumption and CO_2e emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

5.11.2 Turbine Systems CH_4 BACT

CH_4 emissions from the natural gas and fuel oil-fired combustion turbines form as a result of incomplete combustion of hydrocarbons present in the natural gas fuel.

5.11.2.1 Identification of Potential CH_4 Control Technologies (Step 1)

The only available control options for minimizing CH_4 emissions from the combustion turbine systems are efficient turbine operation coupled with good combustion, operating, and maintenance practices to minimize unburned fuel. Oxidation catalysts are not considered available for reducing CH_4 emissions because oxidizing the very low concentrations of CH_4 present in the combustion turbine's exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing CH_4 emissions from gas-fired combustion turbines.

5.11.2.2 Technically Infeasible CH_4 Control Options (Step 2)

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are the only technically feasible control options for reducing CH_4 emissions from the combustion turbines.

5.11.2.3 Summary and Ranking of Remaining CH_4 Control Technologies (Step 3)

Since efficient turbine operation coupled with good combustion, operating, and maintenance practices are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

5.11.2.4 Evaluation of Most Stringent CH_4 Control Technologies (Step 4)

No adverse energy, environment, or economic impacts are associated with efficient turbine operation and good combustion, operating, and maintenance practices for reducing CH_4 emissions from the combustion turbine.

5.11.2.5 Selection of CH_4 BACT (Step 5)

Efficient turbine design and good combustion, operating, and maintenance practices are the selected control options for minimizing CH_4 emissions from the combustion turbine systems. WCP has determined that a numerical limit for CH_4 is unnecessary and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for CH_4 BACT, in addition to the aforementioned CO_2e limit as proposed in Section 5.11.1.5. The CH_4 portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 25 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

5.11.3 Turbine Systems N_2O BACT

For the proposed projects, the contribution of N_2O to the total CO_2e emissions is trivial and therefore should not warrant a detailed BACT review. Nevertheless, the additional information provided supports the rationale that the proposed projects meet BACT for contributions of N_2O to CO_2e.

A tradeoff between NO_X and N_2O emissions from the combustion turbines exists when developing a combustion control strategy which influences the BACT selection process. There are five (5) primary pathways of NO_X production in gas-fired combustion turbine combustion processes: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. For turbines using DLN combustors, the N_2O pathway is an important mechanism of NO_X formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the N_2O molecule, creating N_2 and NO.[212] In premixed gas flames, N_2O is primarily formed in the flame front or oxidation zone. Once formed, the N_2O is readily destroyed due to the relatively high concentration of H radicals, and therefore, the N_2O emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the N_2O formation zone can increase N_2O emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream which are all common NO_X control measures.[213] Therefore, there is a tradeoff between NO_X and N_2O emissions when developing a combustion control strategy which influences the BACT selection process.

5.11.3.1 Identification of Potential N_2O Control Technologies (Step 1)

N_2O catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[214] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

5.11.3.2 Technically Infeasible N_2O Control Options (Step 2)

N_2O catalyst providers do not offer products to control N_2O emissions from gas-fired combustion turbines due to the very low N_2O concentrations present in exhaust streams (approximately 5 ppm).[215] In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in the exhaust stream.

With N_2O catalysts eliminated, good combustion practice is the only available control option.

Good combustion practices are technically feasible control options for reducing N_2O emissions from the combustion turbines.

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[212] Angello, L., Electric Power Research Institute, *Fuel Composition Impacts on Combustion Turbine Operability*, March 2006.

[213] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, February 2004.

[214] *N_20 Emissions from Adipic Acid and Nitric Acid Production*, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

[215] *Emissions of Nitrous Oxide from Combustion Sources,* in Progress and Energy and Combustion Science 18(6): pages 529-552 , December 1992, found at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources

5.11.3.3 Summary and Ranking of Remaining N_2O Control Technologies (Step 3)

Since good combustion practices are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

5.11.3.4 Evaluation of Most Stringent N_2O Control Technologies (Step 4)

As indicated in U.S. EPA's guidance on GHG BACT, GHG control strategies may have the potential to produce higher criteria pollutants as in the case of the competing NO_X and N_2O combustion control strategies for WCP's combustion turbine systems. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.[216]

Given the low N_2O emissions relative to NO_X emissions from the combustion turbine systems and U.S. EPA's continued concern over adverse impacts from ozone formation due to NO_X and VOC emissions, WCP does not consider it appropriate to control the combustion processes of the combustion turbine to specifically reduce N_2O emissions due to the counteractive increase in NO_X emissions. Therefore, good combustion practice for the specific purpose of minimizing N_2O formation is eliminated on the basis of adverse criteria pollutant impacts.

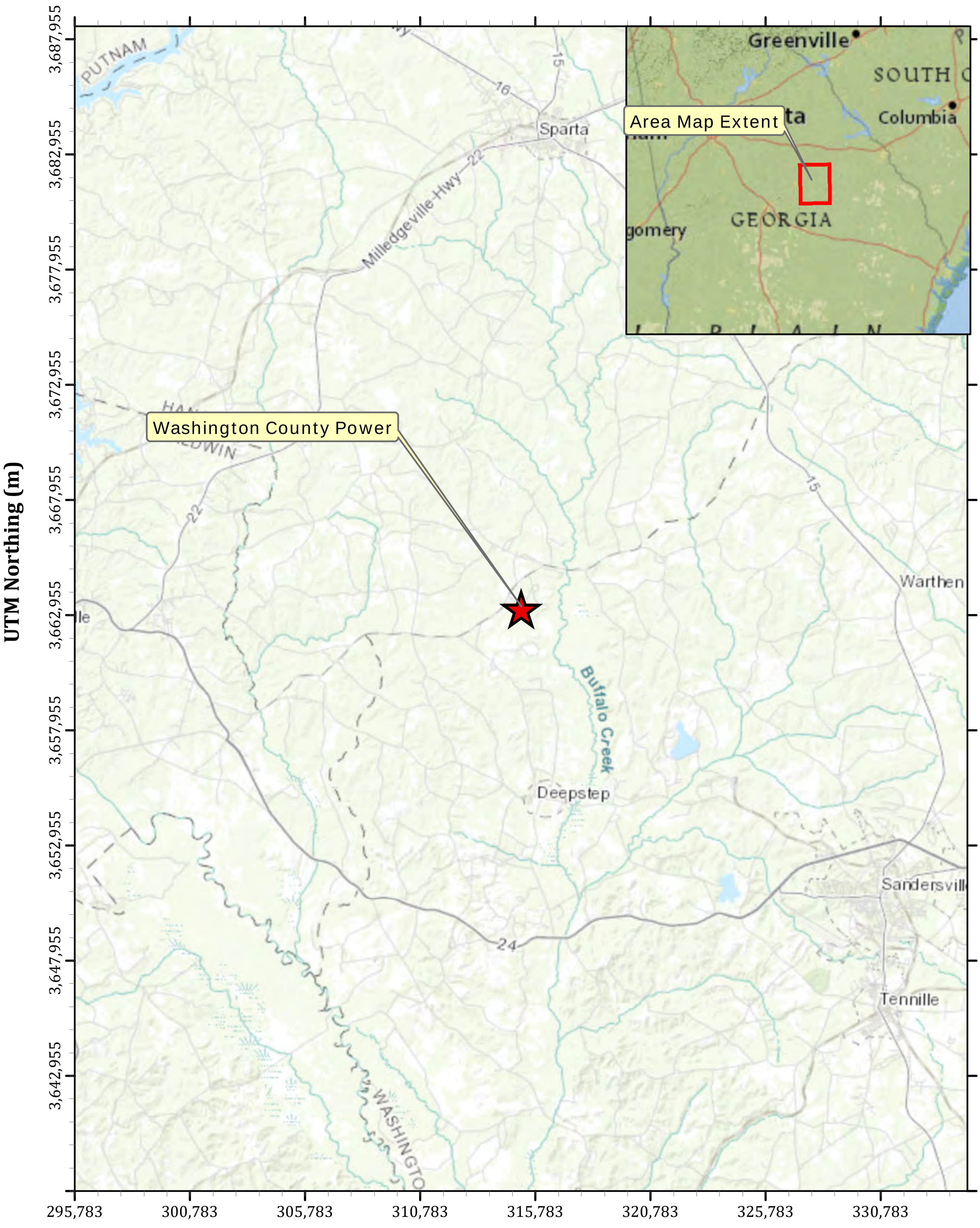
5.11.3.5 Selection of N_2O BACT (Step 5)

Efficient turbine design and general good combustion, operating, and maintenance practices are the selected control options for reducing N_2O emissions from the combustion turbines. WCP has determined that a numerical limit for N_2O emissions is unnecessary and that the work practices required for CO_2 BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for N_2O BACT, in addition to the aforementioned CO_2e limit as proposed in Section 5.11.1.5. The N_2O portion of the proposed CO_2e BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 298 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

216 *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

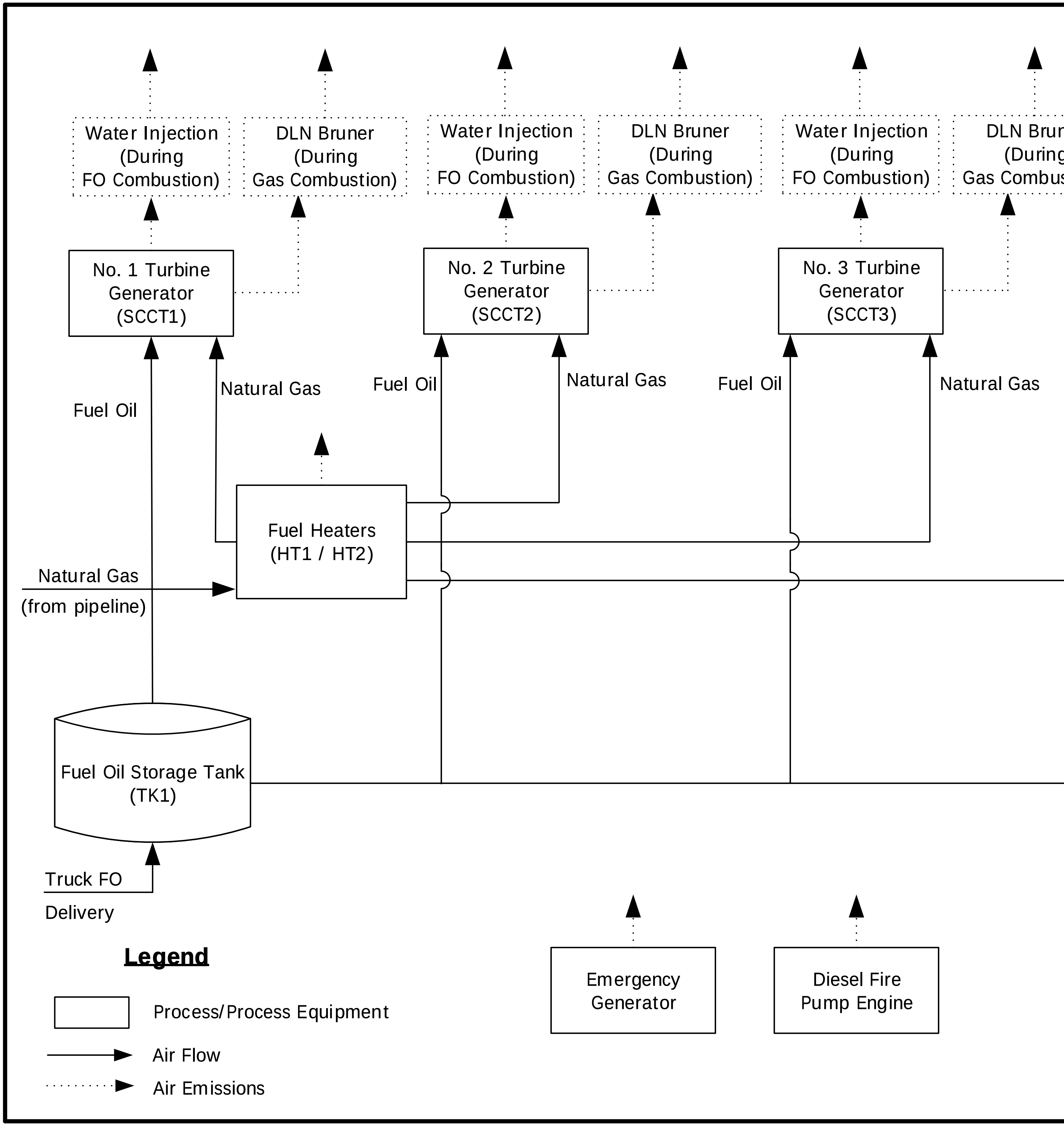
APPENDIX A. AREA MAP AND PROCESS FLOW DIAGRAM

Appendix A-1. Area Map
Washington County Power, LLC - Sandersville, Washington County , Georgia



All Coordinates shown in UTM Coordinates,
Zone 17, NAD 83 Datum

Trinity Consultants



Washington County Power, LLC
Sandersville, GA

Appendix A-2. Process Flow Diagram

Trinity Consultants

200101.0039
January 2021

APPENDIX B. EMISSION CALCULATIONS

Table B-1. Historical Combustion Turbine Heat Inputs[1]

Month	T1 - Combustion Turbine No. 1 (MMBtu/mo.)	T2 - Combustion Turbine No. 2 (MMBtu/mo.)	T3 - Combustion Turbine No. 3 (MMBtu/mo.)	T4 - Combustion Turbine No. 4 (MMBtu/mo.)
Jun-11	91,812	111,102	112,819	110,662
Jul-11	67,805	84,607	84,990	60,092
Aug-11	109,101	136,071	156,681	111,833
Sep-11	14,714	80,365	77,645	21,573
Oct-11	1,909	25,063	29,392	1,879
Nov-11	3,908	63,429	87,342	-
Dec-11	24,115	56,339	55,443	20,213
Jan-12	-	26,176	29,098	-
Feb-12	-	29,153	28,839	-
Mar-12	150,690	37,508	64,335	-
Apr-12	362,834	53,247	91,107	102,506
May-12	144,729	79,526	94,150	105,571
Jun-12	70,522	60,567	191,175	90,143
Jul-12	200,920	97,697	261,287	166,686
Aug-12	8,039	79,958	83,104	39,458
Sep-12	-	43,236	63,247	-
Oct-12	55.00	41.00	49	50
Nov-12	-	31,002	9,550	-
Dec-12	-	-	-	-
Jan-13	2,041	-	-	-
Feb-13	-	-	-	-
Mar-13	1,053	1,151	931	3,359
Apr-13	11,265	47,847	19,704	1,840
May-13	-	-	-	-
Jun-13	21,008	34,615	12,784	33,950
Jul-13	295,932	102,463	194,042	388,883
Aug-13	-	10,800	10,662	-
Sep-13	-	22,238	9,096	-
Oct-13	3,494	54,781	54,503	1,911
Nov-13	9,901	29,194	21,241	-
Dec-13	-	-	-	-
Jan-14	-	139.0	1,978	-
Feb-14	-	-	10,287	-
Mar-14	29,155	872.0	1,124	1,001
Apr-14	-	14,058	31,136	-
May-14	-	20,461	23,895	-
Jun-14	13,092	23,547	23,705	36,301
Jul-14	-	15,716	24,295	-
Aug-14	32,518	37,297	9,075	32,220
Sep-14	18,011	13,385	13,745	-
Oct-14	14,425	42,810	43,120	14,377
Nov-14	13,948	36,261	32,902	8,123
Dec-14	-	-	-	-
Jan-15	-	-	2,003	1,822
Feb-15	-	33,556	-	-
Mar-15	1,751	13,086	1,021	1,795
Apr-15	-	-	-	-
May-15	81,419	59,147	71,588	81,507
Jun-15	186,588	46,928	33,749	183,588
Jul-15	236,173	127,366	154,240	215,068
Aug-15	19,127	11,629	47,327	-
Sep-15	76,538	56,281	36,191	37,038
Oct-15	16,124	1,716	1,667	1,630
Nov-15	115,601	6,663	-	101,283
Dec-15	-	-	-	-

Table B-1. Historical Combustion Turbine Heat Inputs[1]

Month	T1 - Combustion Turbine No. 1 (MMBtu/mo.)	T2 - Combustion Turbine No. 2 (MMBtu/mo.)	T3 - Combustion Turbine No. 3 (MMBtu/mo.)	T4 - Combustion Turbine No. 4 (MMBtu/mo.)
Jan-16	-	71,034	43,400	-
Feb-16	-	-	-	-
Mar-16	1,626	118,452	70,238	854.0
Apr-16	-	169,627	158,005	-
May-16	-	6,588	41,573	15,838
Jun-16	32,227	85,782	85,200	22,896
Jul-16	-	51,224	7,179	41,330
Aug-16	-	28,672	-	-
Sep-16	-	76,214	55,625	-
Oct-16	17,675	87,576	41,360	17,324
Nov-16	-	14,697	17,247	-
Dec-16	-	10,965	11,048	-
Jan-17	-	-	-	-
Feb-17	-	-	-	-
Mar-17	878.0	70,338	22,081	1,137
Apr-17	-	93,307	93,171	-
May-17	19,289	79,128	66,118	19,327
Jun-17	-	9,681	7,866	-
Jul-17	57,070	78,655	77,164	57,575
Aug-17	-	127,906	110,791	-
Sep-17	-	116,749	107,540	-
Oct-17	1,106	19,593	1,003	1,012
Nov-17	-	11,934	11,299	-
Dec-17	-	-	-	-
Jan-18	-	-	-	-
Feb-18	-	-	-	-
Mar-18	1,080	5,349	6,226	929.0
Apr-18	-	14,064	39,563	-
May-18	39,336	35,367	9,703	64,982
Jun-18	95,006	57,977	55,837	117,506
Jul-18	17,985	45,619	29,060	-
Aug-18	-	50,946	50,746	-
Sep-18	33,730	64,877	59,041	60,709
Oct-18	27,214	79,106	108,821	53,586
Nov-18	-	-	-	-
Dec-18	-	10,790	11,060	-
Jan-19	-	-	-	-
Feb-19	-	-	-	-
Mar-19	979.0	1,392	1,035	1,073
Apr-19	-	7,073	6,855	-
May-19	34,615	22,820	12,309	-
Jun-19	77,554	35,423	35,235	51,823
Jul-19	37,239	141,423	138,330	191,935
Aug-19	104,086	118,577	116,818	-
Sep-19	217,892	174,599	172,044	249,492
Oct-19	85,573	95,217	92,952	104,699
Nov-19	-	21,958	9,388	-
Dec-19	954.0	1,087	1,030	1,055
Jan-20	-	-	-	-
Feb-20	-	-	-	-
Mar-20	41,652	1,087	1,073	977.0
Apr-20	-	-	-	-
May-20	-	-	-	-
Jun-20	24,613	80,186	60,452	13,174

1. Heat inputs represent historically measured site data.

Table B-2. Historically Monitored Emissions[1]

	T1 - Combustion Turbine No. 1			T2 - Combustion Turbine No. 2			T3 - Combustion Turbine No. 3			T4 - Combustion Turbine No. 4		
Month	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)
Jun-11	2.00	-	5,456	2.60	-	6,603	2.20	-	6,704	2.20	-	6,577
Jul-11	1.50	-	4,030	1.90	-	5,028	1.70	-	5,051	1.30	-	3,571
Aug-11	2.50	-	6,484	3.20	-	8,086	3.20	-	9,311	2.50	-	6,646
Sep-11	0.40	-	874	1.80	-	4,776	1.50	-	4,615	0.60	-	1,282
Oct-11	0.20	-	113	0.60	-	1,489	0.60	-	1,747	0.10	-	112
Nov-11	0.20	-	232	1.40	-	3,769	1.80	-	5,191	-	-	-
Dec-11	0.60	-	1,433	1.40	-	3,348	1.20	-	3,295	0.40	-	1,201
Jan-12	-	-	-	0.70	-	1,556	0.70	-	1,729	-	-	-
Feb-12	-	-	-	0.80	-	1,733	0.70	-	1,714	-	-	-
Mar-12	3.40	-	8,956	0.90	-	2,229	1.20	-	3,824	-	-	-
Apr-12	6.30	0.10	21,563	1.20	-	3,164	1.70	-	5,414	2.00	-	6,092
May-12	2.40	-	8,601	1.70	-	4,726	1.60	-	5,595	1.50	-	6,274
Jun-12	1.40	-	4,191	1.30	-	3,600	3.60	0.10	11,362	1.60	-	5,357
Jul-12	3.60	0.10	11,940	2.00	-	5,806	4.60	0.10	15,528	2.80	0.10	9,906
Aug-12	0.10	-	478	1.70	-	4,752	1.50	-	4,939	0.60	-	2,345
Sep-12	-	-	-	0.90	-	2,570	1.20	-	3,759	-	-	-
Oct-12	-	-	3	-	-	2	-	-	3	-	-	3
Nov-12	-	-	-	0.70	-	1,843	0.20	-	568	-	-	-
Dec-12	-	-	-	-	-	-	-	-	-	-	-	-
Jan-13	0.10	-	121	-	-	-	-	-	-	-	-	-
Feb-13	-	-	-	-	-	-	-	-	-	-	-	-
Mar-13	0.10	-	63	0.10	-	68	0.10	-	55	0.20	-	200
Apr-13	0.20	-	670	1.10	-	2,844	0.40	-	1,171	0.10	-	109
May-13	-	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.40	-	1,249	0.70	-	2,057	0.20	-	760	0.60	-	2,018
Jul-13	5.10	0.10	17,586	2.00	-	6,090	3.20	0.10	11,532	6.60	0.10	23,110
Aug-13	-	-	-	0.20	-	642	0.20	-	634	-	-	-
Sep-13	-	-	-	0.50	-	1,322	0.20	-	541	-	-	-
Oct-13	0.10	-	208	1.20	-	3,256	1.10	-	3,239	0.10	-	114
Nov-13	0.20	-	588	0.60	-	1,735	0.40	-	1,262	-	-	-
Dec-13	-	-	-	-	-	-	-	-	-	-	-	-
Jan-14	-	-	-	-	-	8	0.10	-	118	-	-	-
Feb-14	-	-	-	-	-	-	0.20	-	612	-	-	-
Mar-14	0.60	-	1,733	0.10	-	52	0.10	-	67	-	-	60
Apr-14	-	-	-	0.30	-	836	0.60	-	1,850	-	-	-
May-14	-	-	-	0.50	-	1,216	0.50	-	1,420	-	-	-
Jun-14	0.20	-	778	0.50	-	1,399	0.40	-	1,409	0.60	-	2,157
Jul-14	-	-	-	0.40	-	934	0.50	-	1,444	-	-	-
Aug-14	0.60	-	1,933	0.90	-	2,216	0.20	-	539	0.60	-	1,915
Sep-14	0.30	-	1,071	0.30	-	795	0.30	-	817	-	-	-
Oct-14	0.30	-	857	1.00	-	2,544	0.90	-	2,562	0.30	-	854
Nov-14	0.30	-	829	0.90	-	2,155	0.70	-	1,956	0.20	-	483
Dec-14	-	-	-	-	-	-	-	-	-	-	-	-
Jan-15	-	-	-	-	-	-	0.10	-	119	0.10	-	108
Feb-15	-	-	-	0.90	-	1,994	-	-	-	-	-	-
Mar-15	0.10	-	104	0.40	-	778	0.10	-	61	0.10	-	107
Apr-15	-	-	-	-	-	-	-	-	-	-	-	-
May-15	1.40	-	4,839	1.40	-	3,515	1.50	-	4,255	1.40	-	4,844
Jun-15	3.10	0.10	11,089	1.10	-	2,789	0.60	-	2,006	3.20	0.10	10,910
Jul-15	4.10	0.10	14,035	2.80	-	7,569	3.00	-	9,167	3.80	0.10	12,781
Aug-15	0.30	-	1,137	0.30	-	691	0.90	-	2,813	-	-	-
Sep-15	1.20	-	4,548	1.20	-	3,345	0.80	-	2,151	0.50	-	2,201
Oct-15	0.30	-	958	-	-	102	-	-	99	0.10	-	97
Nov-15	1.90	-	6,870	0.20	-	396	-	-	-	1.60	-	6,020
Dec-15	-	-	-	-	-	-	-	-	-	-	-	-
Jan-16	-	-	-	2.10	-	4,222	1.10	-	2,579	-	-	-
Feb-16	-	-	-	-	-	-	-	-	-	-	-	-
Mar-16	0.10	-	97	2.70	-	7,040	1.40	-	4,174	0.10	-	51
Apr-16	-	-	-	4.80	0.10	10,081	3.20	-	9,390	-	-	-
May-16	-	-	-	0.10	-	392	0.90	-	2,471	0.20	-	941
Jun-16	0.50	-	1,915	3.40	-	5,098	1.60	-	5,064	0.40	-	1,360
Jul-16	-	-	-	1.30	-	3,045	0.10	-	427	0.60	-	2,456
Aug-16	-	-	-	0.70	-	1,704	-	-	-	-	-	-
Sep-16	-	-	-	1.90	-	4,529	1.10	-	3,306	-	-	-
Oct-16	0.30	-	1,050	2.30	-	5,204	1.10	-	2,458	0.30	-	1,030
Nov-16	-	-	-	0.40	-	873	0.40	-	1,025	-	-	-
Dec-16	-	-	-	0.30	-	652	0.30	-	657	-	-	-
Jan-17	-	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-	-
Mar-17	-	-	52	1.90	-	4,180	0.60	-	1,312	0.10	-	68
Apr-17	-	-	-	2.30	-	5,546	2.20	-	5,537	-	-	-
May-17	0.40	-	1,146	2.00	-	4,702	1.60	-	3,929	0.30	-	1,148
Jun-17	-	-	-	0.30	-	575	0.20	-	468	-	-	-
Jul-17	1.00	-	3,392	1.90	-	4,674	2.70	-	4,586	0.80	-	3,422
Aug-17	-	-	-	2.90	-	7,602	2.40	-	6,585	-	-	-
Sep-17	-	-	-	2.80	-	6,938	2.50	-	6,391	-	-	-
Oct-17	0.10	-	66	0.50	-	1,164	0.10	-	60	0.10	-	60
Nov-17	-	-	-	0.30	-	709	0.30	-	672	-	-	-
Dec-17	-	-	-	-	-	-	-	-	-	-	-	-

Table B-2. Historically Monitored Emissions[1]

Month	T1 - Combustion Turbine No. 1			T2 - Combustion Turbine No. 2			T3 - Combustion Turbine No. 3			T4 - Combustion Turbine No. 4		
	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO_2 (tons/mo.)
Jan-18	-	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-	-
Mar-18	-	-	64	0.20	-	318	0.20	-	370	0.10	-	55
Apr-18	-	-	-	0.40	-	836	0.80	-	2,351	-	-	-
May-18	0.80	-	2,338	0.80	-	2,102	0.20	-	577	1.10	-	3,861
Jun-18	1.50	-	5,646	1.30	-	3,445	1.20	-	3,319	1.50	-	6,984
Jul-18	0.30	-	1,069	1.00	-	2,711	0.60	-	1,727	-	-	-
Aug-18	-	-	-	1.10	-	3,028	1.10	-	3,016	-	-	-
Sep-18	0.60	-	2,004	1.50	-	3,855	1.30	-	3,509	0.90	-	3,608
Oct-18	0.50	-	1,617	1.80	-	4,701	2.50	-	6,467	0.70	-	3,185
Nov-18	-	-	-	-	-	-	-	-	-	-	-	-
Dec-18	-	-	-	0.30	-	641	0.30	-	657	-	-	-
Jan-19	-	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-	-
Mar-19	-	-	58	0.10	-	83	-	-	62	-	-	64
Apr-19	-	-	-	0.20	-	420	0.20	-	407	-	-	-
May-19	0.60	-	2,057	0.50	-	1,356	0.30	-	731	-	-	-
Jun-19	1.20	-	4,609	0.80	-	2,105	0.70	-	2,094	0.60	-	3,080
Jul-19	0.60	-	2,213	3.00	-	8,404	2.80	-	8,221	2.50	0.10	11,408
Aug-19	1.60	-	6,186	2.50	-	7,047	2.30	-	6,942	-	-	-
Sep-19	3.80	0.10	12,948	3.90	0.10	10,377	3.70	0.10	10,225	3.30	0.10	14,826
Oct-19	1.50	-	5,085	2.10	-	5,658	2.00	-	5,524	1.50	-	6,222
Nov-19	-	-	-	0.60	-	1,305	0.30	-	558	-	-	-
Dec-19	0.10	-	57	0.10	-	65	0.10	-	61	0.10	-	63
Jan-20	-	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-	-
Mar-20	0.80	-	2,475	0.10	-	65	-	-	64	0.10	-	58
Apr-20	-	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.40	-	1,463	1.90	-	4,765	1.30	-	3,592	0.20	-	783

1. Emissions data represent historically measured site data (CEMS units).

Table B-3. Emission Factors for Turbine Combustion of Natural Gas

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis
SO_2	6.00E-04	See Note 1
NO_X	3.00E-02	See Note 2
CO	1.82E-02	See Note 2
Total PM	1.37E-02	See Notes 1, 3
Filterable PM	9.00E-03	See Note 1
Condensable PM	4.70E-03	See Note 3
Total PM_{10}	1.37E-02	See Notes 1, 3, 4
Total $PM_{2.5}$	1.37E-02	See Notes 1, 3, 4
VOC	6.37E-03	See Note 2
Sulfuric Acid Mist (H_2SO_4)	4.00E-04	See Note 1
GHGs		
CO_2	116.98	See Note 5
CH_4	2.20E-03	See Note 5
N_2O	2.20E-04	See Note 5
CO_2e	117.10	See Note 6

1. Emission factors for natural gas combustion are obtained from the emission limitations in the currently effective Major Source Operating Permit No. 301-0073 for the Calhoun Energy Center (a similar facility). SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1

2. NO_X/CO/VOC Rate (lb/MMBtu) = Concentration (ppm, or lb-mole pollutant/10^6 lb-mol air) * Molecular Weight (lb /lb-mol) * Flow (dscfm) * 60 min/hr / Ideal Volume (ft^3 air/lb-mol air) / Turbine Heat Input (MMBtu/hr); where

NO_X Molecular Weight	46.01	lb NO_X/lb-mol NO_X
CO Molecular Weight	28.01	lb CO/lb-mol CO
VOC Molecular Weight	44	lb VOC/lb-mol NH_3
Turbine Flow rate	820,699	dscfm
$Volume_{ideal}$	385.5	ft^3 air/lb-mol air
Turbine Heat Input	1,766	MMBtu/hr
NO_X Conc. (ppm)	9	BACT selection
CO Conc. (ppm)	9	BACT selection
VOC Conc. (ppm)	2	BACT selection

3. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emissions of PM_{10} and $PM_{2.5}$ are assumed to be equivalent to emissions of total PM.

5. Based on EPA default factors in 40 CFR Part 98 Subpart C Tables C-1 and C-2, effective January 1, 2014, for Natural Gas. Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.

6. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1:

CO_2:	1
CH_4:	25
N_2O:	298

Table B-4. Emission Factors for Turbine Combustion of Fuel Oil

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis
SO_2	1.50E-03	See Note 1
NO_X	1.40E-01	See Note 2
CO	4.05E-02	See Note 2
Total PM	1.42E-02	See Note 3
Filterable PM	7.00E-03	See Note 4
Condensable PM	7.20E-03	See Note 5
Total PM_{10}	1.42E-02	See Notes 3, 6
Total $PM_{2.5}$	1.42E-02	See Notes 3, 6
VOC	1.59E-02	See Note 2
Lead	1.40E-05	See Note 5
Sulfuric Acid Mist (H_2SO_4)	3.90E-03	See Note 1
GHGs		
CO_2	163.05	See Note 7
CH_4	6.61E-03	See Note 7
N_2O	1.32E-03	See Note 7
CO_2e	163.61	See Note 8

1. SO_2 and H_2SO_4 emission factor is based on the combustion of Ultra Low Sulfur Diesel.
2. NO_X/CO/VOC Rate (lb/MMBtu) = Concentration (ppm, or lb-mole pollutant/10^6 lb-mol air) * Molecular Weight (lb /lb-mol) * Flow (dscfm) * 60 min/hr / Ideal Volume (ft^3 air/lb-mol air) / Turbine Heat Input (MMBtu/hr); where

NO_X Molecular Weight	46.01	lb NO_X/lb-mol NO_X
CO Molecular Weight	28.01	lb CO/lb-mol CO
VOC Molecular Weight	44	lb VOC/lb-mol NH_3
Turbine Flow rate	878,148	dscfm
$Volume_{ideal}$	385.5	ft^3 air/lb-mol air
Turbine Heat Input	1,890	MMBtu/hr
NO_X Conc. (ppm)	42	BACT Selection
CO Conc. (ppm)	20	BACT Selection
VOC Conc. (ppm)	5	BACT Selection

3. Emission factor for Total PM is based on site-specific data and proposed BACT limit.
4. Emission factor for Filterable PM is the delta between the Total PM and Condensable PM emission factors.
5. Emission factors for fuel oil are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).
6. Emissions of PM_{10} and $PM_{2.5}$ are assumed to be equivalent to emissions of total PM.
7. Based on EPA default factors in 40 CFR Part 98 Subpart C Tables C-1 and C-2, effective January 1, 2014, for Petroleum Products/Distillate Fuel Oil No. 2. Emission factors were converted from units of kg/MMBtu to lb/MMBtu by multiplying the factors by 2.2046 lb/kg.
8. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1:

CO_2: 1
CH_4: 25
N_2O: 298

Table B-5. Emission Factors for Turbine Startup/Shutdown Operations

Pollutant	Emission Factors[1] (lb/MMBtu)	Operation Hours/ Events[2]
Startup/Shutdown Natural Gas		
NO_X	0.05	300 hrs natural gas
CO	0.03	
VOC	0.01	
Startup/Shutdown Fuel Oil		
NO_X	0.25	50 hrs fuel oil
CO	0.07	
VOC	0.03	

1. Startup/shutdown emission factors based on review and engineering analysis of existing source operational data for SUSD activities.
2. Assumes approximately 10% of estimated operating time per turbine is considered for SUSD activities.

Table B-6. Fuel Heater Emission Factors

Pollutant	Emission Factor (lb/MMscf)	Emission Factor Basis
SO_2	1.43	See Note 1
NO_X	100.00	See Note 2
CO	84.00	See Note 2
Total PM	7.60	See Note 2
Condensable PM	5.70	See Note 2
Filterable PM	1.90	See Note 2
Total PM_{10}	7.60	See Notes 2, 3
Total $PM_{2.5}$	7.60	See Notes 2, 3
VOC	5.50	See Note 2
Lead	5.00E-04	See Note 2
H_2SO_4	3.28E-01	See Note 4
GHGs		
CO_2	119,317	See Note 5
CH_4	2.25	See Note 5
N_2O	2.25E-01	See Note 5
CO_2e	119,440	See Note 6

1. Emission factor calculated based on the assumption that sulfur content in natural gas is 0.50 grains/100 scf. Emission factor calculated as follows:
Emission Factor (lb/MMscf) = (0.5 grains sulfur/100 scf) / (7,000 grains sulfur/lb-mol S) * (64 lb-mol SO_2) / (32 lb-mol S)
2. Emission factors obtained from AP-42 Ch. 1.4 Natural Gas Combustion, Tables 1.4-1 & 2 (July 1998).
3. Emissions of PM_{10} and $PM_{2.5}$ are assumed to be equivalent to emissions of total PM.
4. Emission factor calculated using the assumption that sulfur content in natural gas is 0.50 grains/100 scf and a 15% oxidation rate. Emission factor calculated as follows:
Emission Factor (lb/MMscf) = (0.5 grains sulfur/100 scf) / (7,000 grains sulfur/lb-mol S) * (98 lb-mol H_2SO_4) / (32 lb-mol S) * 0.15
5., Based on EPA default factors in 40 CFR Part 98 Subpart C Tables C-1 and C-2, effective January 1, 2014, for Natural Gas. Emission factors were converted from units of kg/MMBtu to lb/MMscf as follows:
Emission Factor (lb/MMscf) = Emission Factor (kg/MMBtu) * 2.2046 (lb/kg) * 1,020 (MMBtu/MMscf)
6. The CO_2e factor is calculated based on the emission factors for CO_2, CH_4, and N_2O and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1:

CO_2: 1
CH_4: 25
N_2O: 298

Table B-7. Historical Actual Monthly Emissions from Combustion Turbine No. 1 (tons/month) [1,2]

	T1 - Combustion Turbine No. 1										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e^3**
Jun-11	0.41	0.22	0.63	0.63	0.63	-	2.00	0.84	0.29	0.02	5,462
Jul-11	0.31	0.16	0.46	0.46	0.46	-	1.50	0.62	0.22	0.01	4,034
Aug-11	0.49	0.26	0.75	0.75	0.75	-	2.50	0.99	0.35	0.02	6,490
Sep-11	0.07	0.03	0.10	0.10	0.10	-	0.40	0.13	0.05	2.94E-03	875
Oct-11	0.01	4.49E-03	0.01	0.01	0.01	-	0.20	0.02	0.01	3.82E-04	114
Nov-11	0.02	0.01	0.03	0.03	0.03	-	0.20	0.04	0.01	7.82E-04	232
Dec-11	0.11	0.06	0.17	0.17	0.17	-	0.60	0.22	0.08	4.82E-03	1,435
Jan-12	-	-	-	-	-	-	-	-	-	-	-
Feb-12	-	-	-	-	-	-	-	-	-	-	-
Mar-12	0.68	0.35	1.03	1.03	1.03	-	3.40	1.37	0.48	0.03	8,965
Apr-12	1.63	0.85	2.49	2.49	2.49	0.10	6.30	3.31	1.15	0.07	21,585
May-12	0.65	0.34	0.99	0.99	0.99	-	2.40	1.32	0.46	0.03	8,610
Jun-12	0.32	0.17	0.48	0.48	0.48	-	1.40	0.64	0.22	0.01	4,195
Jul-12	0.90	0.47	1.38	1.38	1.38	0.10	3.60	1.83	0.64	0.04	11,952
Aug-12	0.04	0.02	0.06	0.06	0.06	-	0.10	0.07	0.03	1.61E-03	478
Sep-12	-	-	-	-	-	-	-	-	-	-	-
Oct-12	2.48E-04	1.29E-04	3.77E-04	3.77E-04	3.77E-04	-	-	5.01E-04	1.75E-04	1.10E-05	3
Nov-12	-	-	-	-	-	-	-	-	-	-	-
Dec-12	-	-	-	-	-	-	-	-	-	-	-
Jan-13	0.01	4.80E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	4.08E-04	121
Feb-13	-	-	-	-	-	-	-	-	-	-	-
Mar-13	4.74E-03	2.47E-03	0.01	0.01	0.01	-	0.10	0.01	3.35E-03	2.11E-04	63
Apr-13	0.05	0.03	0.08	0.08	0.08	-	0.20	0.10	0.04	2.25E-03	670
May-13	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.09	0.05	0.14	0.14	0.14	-	0.40	0.19	0.07	4.20E-03	1,250
Jul-13	1.33	0.70	2.03	2.03	2.03	0.10	5.10	2.70	0.94	0.06	17,604
Aug-13	-	-	-	-	-	-	-	-	-	-	-
Sep-13	-	-	-	-	-	-	-	-	-	-	-
Oct-13	0.02	0.01	0.02	0.02	0.02	-	0.10	0.03	0.01	6.99E-04	208
Nov-13	0.04	0.02	0.07	0.07	0.07	-	0.20	0.09	0.03	1.98E-03	589
Dec-13	-	-	-	-	-	-	-	-	-	-	-
Jan-14	-	-	-	-	-	-	-	-	-	-	-
Feb-14	-	-	-	-	-	-	-	-	-	-	-
Mar-14	0.13	0.07	0.20	0.20	0.20	-	0.60	0.27	0.09	0.01	1,734
Apr-14	-	-	-	-	-	-	-	-	-	-	-
May-14	-	-	-	-	-	-	-	-	-	-	-
Jun-14	0.06	0.03	0.09	0.09	0.09	-	0.20	0.12	0.04	2.62E-03	779
Jul-14	-	-	-	-	-	-	-	-	-	-	-
Aug-14	0.15	0.08	0.22	0.22	0.22	-	0.60	0.30	0.10	0.01	1,934
Sep-14	0.08	0.04	0.12	0.12	0.12	-	0.30	0.16	0.06	3.60E-03	1,072
Oct-14	0.06	0.03	0.10	0.10	0.10	-	0.30	0.13	0.05	2.89E-03	858
Nov-14	0.06	0.03	0.10	0.10	0.10	-	0.30	0.13	0.04	2.79E-03	830
Dec-14	-	-	-	-	-	-	-	-	-	-	-
Jan-15	-	-	-	-	-	-	-	-	-	-	-
Feb-15	-	-	-	-	-	-	-	-	-	-	-
Mar-15	0.01	4.11E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.50E-04	104
Apr-15	-	-	-	-	-	-	-	-	-	-	-
May-15	0.37	0.19	0.56	0.56	0.56	-	1.40	0.74	0.26	0.02	4,844
Jun-15	0.84	0.44	1.28	1.28	1.28	0.10	3.10	1.70	0.59	0.04	11,100
Jul-15	1.06	0.56	1.62	1.62	1.62	0.10	4.10	2.15	0.75	0.05	14,049
Aug-15	0.09	0.04	0.13	0.13	0.13	-	0.30	0.17	0.06	3.83E-03	1,138
Sep-15	0.34	0.18	0.52	0.52	0.52	-	1.20	0.70	0.24	0.02	4,553
Oct-15	0.07	0.04	0.11	0.11	0.11	-	0.30	0.15	0.05	3.22E-03	959
Nov-15	0.52	0.27	0.79	0.79	0.79	-	1.90	1.05	0.37	0.02	6,877
Dec-15	-	-	-	-	-	-	-	-	-	-	-
Jan-16	-	-	-	-	-	-	-	-	-	-	-
Feb-16	-	-	-	-	-	-	-	-	-	-	-
Mar-16	0.01	3.82E-03	0.01	0.01	0.01	-	0.10	0.01	0.01	3.25E-04	97
Apr-16	-	-	-	-	-	-	-	-	-	-	-
May-16	-	-	-	-	-	-	-	-	-	-	-
Jun-16	0.15	0.08	0.22	0.22	0.22	-	0.50	0.29	0.10	0.01	1,917
Jul-16	-	-	-	-	-	-	-	-	-	-	-
Aug-16	-	-	-	-	-	-	-	-	-	-	-
Sep-16	-	-	-	-	-	-	-	-	-	-	-
Oct-16	0.08	0.04	0.12	0.12	0.12	-	0.30	0.16	0.06	3.54E-03	1,051
Nov-16	-	-	-	-	-	-	-	-	-	-	-
Dec-16	-	-	-	-	-	-	-	-	-	-	-

Table B-7. Historical Actual Monthly Emissions from Combustion Turbine No. 1 (tons/month) [1,2]

Month	T1 - Combustion Turbine No. 1										
	Filterable PM	Condensable PM	Total PM	Total PM_{10}	Total $PM_{2.5}$	SO_2	NO_X	CO	VOC	Sulfuric Acid Mist (H_2SO_4)	CO_2e[3]
Jan-17	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-
Mar-17	3.95E-03	2.06E-03	0.01	0.01	0.01	-	-	0.01	2.79E-03	1.76E-04	52
Apr-17	-	-	-	-	-	-	-	-	-	-	-
May-17	0.09	0.05	0.13	0.13	0.13	-	0.40	0.18	0.06	3.86E-03	1,147
Jun-17	-	-	-	-	-	-	-	-	-	-	-
Jul-17	0.26	0.13	0.39	0.39	0.39	-	1.00	0.52	0.18	0.01	3,396
Aug-17	-	-	-	-	-	-	-	-	-	-	-
Sep-17	-	-	-	-	-	-	-	-	-	-	-
Oct-17	4.98E-03	2.60E-03	0.01	0.01	0.01	-	0.10	0.01	3.52E-03	2.21E-04	66
Nov-17	-	-	-	-	-	-	-	-	-	-	-
Dec-17	-	-	-	-	-	-	-	-	-	-	-
Jan-18	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-
Mar-18	4.86E-03	2.54E-03	0.01	0.01	0.01	-	-	0.01	3.44E-03	2.16E-04	64
Apr-18	-	-	-	-	-	-	-	-	-	-	-
May-18	0.18	0.09	0.27	0.27	0.27	-	0.80	0.36	0.13	0.01	2,340
Jun-18	0.43	0.22	0.65	0.65	0.65	-	1.50	0.87	0.30	0.02	5,652
Jul-18	0.08	0.04	0.12	0.12	0.12	-	0.30	0.16	0.06	3.60E-03	1,070
Aug-18	-	-	-	-	-	-	-	-	-	-	-
Sep-18	0.15	0.08	0.23	0.23	0.23	-	0.60	0.31	0.11	0.01	2,006
Oct-18	0.12	0.06	0.19	0.19	0.19	-	0.50	0.25	0.09	0.01	1,619
Nov-18	-	-	-	-	-	-	-	-	-	-	-
Dec-18	-	-	-	-	-	-	-	-	-	-	-
Jan-19	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-
Mar-19	4.41E-03	2.30E-03	0.01	0.01	0.01	-	-	0.01	3.12E-03	1.96E-04	58
Apr-19	-	-	-	-	-	-	-	-	-	-	-
May-19	0.16	0.08	0.24	0.24	0.24	-	0.60	0.32	0.11	0.01	2,059
Jun-19	0.35	0.18	0.53	0.53	0.53	-	1.20	0.71	0.25	0.02	4,614
Jul-19	0.17	0.09	0.26	0.26	0.26	-	0.60	0.34	0.12	0.01	2,215
Aug-19	0.47	0.24	0.71	0.71	0.71	-	1.60	0.95	0.33	0.02	6,192
Sep-19	0.98	0.51	1.49	1.49	1.49	0.10	3.80	1.99	0.69	0.04	12,961
Oct-19	0.39	0.20	0.59	0.59	0.59	-	1.50	0.78	0.27	0.02	5,091
Nov-19	-	-	-	-	-	-	-	-	-	-	-
Dec-19	4.29E-03	2.24E-03	0.01	0.01	0.01	-	0.10	0.01	3.04E-03	1.91E-04	57
Jan-20	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-
Mar-20	0.19	0.10	0.29	0.29	0.29	-	0.80	0.38	0.13	0.01	2,478
Apr-20	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.11	0.06	0.17	0.17	0.17	-	0.40	0.22	0.08	4.92E-03	1,464

1. Excluding SO_2 and NO_X, Baseline Emissions calculated as follows:
Baseline Emissions [ton/month] = Turbine Heat Input [MMBtu/month] x Natural Gas Combustion Emission Factor [lb/MMBtu] / 2,000 [lb/ton]
2. Baseline Emissions of SO_2, NO_X, and CO_2 were obtained from historical data provided by Washington County Power.
3. Baseline emissions of CO_2e are calculated using the historical CO_2 emission data provided by Washington County Power, AP-42 Ch. 3.1, Table 3.1-2a (April 2000) emission factors for CH_4 and N_2O, and global warming potentials for CH_4 and N_2O from 40 CFR 98, Subpart A, Table A-1. The Baseline Emissions for CO_2e were calculated as follows:
Baseline Emissions [ton/month] = CO_2 Baseline Emissions [ton/month] + Turbine Heat Input [MMBtu/month] x (CH_4 Emission Factor [lb/MMBtu] x 25 + N_2O Emission Factor [lb/MMBtu] x 298) / 2,000 [lb/ton]

Table B-8. Historical Actual Monthly Emissions from Combustion Turbine No. 2 (tons/month) [1,2]

	T2 - Combustion Turbine No. 2										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e [3]**
Jun-11	0.50	0.26	0.76	0.76	0.76	-	2.60	1.01	0.35	0.02	6,609
Jul-11	0.38	0.20	0.58	0.58	0.58	-	1.90	0.77	0.27	0.02	5,033
Aug-11	0.61	0.32	0.93	0.93	0.93	-	3.20	1.24	0.43	0.03	8,094
Sep-11	0.36	0.19	0.55	0.55	0.55	-	1.80	0.73	0.26	0.02	4,781
Oct-11	0.11	0.06	0.17	0.17	0.17	-	0.60	0.23	0.08	0.01	1,491
Nov-11	0.29	0.15	0.43	0.43	0.43	-	1.40	0.58	0.20	0.01	3,773
Dec-11	0.25	0.13	0.39	0.39	0.39	-	1.40	0.51	0.18	0.01	3,352
Jan-12	0.12	0.06	0.18	0.18	0.18	-	0.70	0.24	0.08	0.01	1,557
Feb-12	0.13	0.07	0.20	0.20	0.20	-	0.80	0.27	0.09	0.01	1,734
Mar-12	0.17	0.09	0.26	0.26	0.26	-	0.90	0.34	0.12	0.01	2,231
Apr-12	0.24	0.13	0.36	0.36	0.36	-	1.20	0.49	0.17	0.01	3,167
May-12	0.36	0.19	0.54	0.54	0.54	-	1.70	0.73	0.25	0.02	4,731
Jun-12	0.27	0.14	0.41	0.41	0.41	-	1.30	0.55	0.19	0.01	3,603
Jul-12	0.44	0.23	0.67	0.67	0.67	-	2.00	0.89	0.31	0.02	5,812
Aug-12	0.36	0.19	0.55	0.55	0.55	-	1.70	0.73	0.25	0.02	4,757
Sep-12	0.19	0.10	0.30	0.30	0.30	-	0.90	0.39	0.14	0.01	2,572
Oct-12	1.85E-04	9.64E-05	2.81E-04	2.81E-04	2.81E-04	-	-	3.74E-04	1.30E-04	8.20E-06	2
Nov-12	0.14	0.07	0.21	0.21	0.21	-	0.70	0.28	0.10	0.01	1,844
Dec-12	-	-	-	-	-	-	-	-	-	-	-
Jan-13	-	-	-	-	-	-	-	-	-	-	-
Feb-13	-	-	-	-	-	-	-	-	-	-	-
Mar-13	0.01	2.70E-03	0.01	0.01	0.01	-	0.10	0.01	3.66E-03	2.30E-04	68
Apr-13	0.22	0.11	0.33	0.33	0.33	-	1.10	0.44	0.15	0.01	2,846
May-13	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.16	0.08	0.24	0.24	0.24	-	0.70	0.32	0.11	0.01	2,059
Jul-13	0.46	0.24	0.70	0.70	0.70	-	2.00	0.93	0.33	0.02	6,096
Aug-13	0.05	0.03	0.07	0.07	0.07	-	0.20	0.10	0.03	2.16E-03	642
Sep-13	0.10	0.05	0.15	0.15	0.15	-	0.50	0.20	0.07	4.45E-03	1,323
Oct-13	0.25	0.13	0.38	0.38	0.38	-	1.20	0.50	0.17	0.01	3,259
Nov-13	0.13	0.07	0.20	0.20	0.20	-	0.60	0.27	0.09	0.01	1,737
Dec-13	-	-	-	-	-	-	-	-	-	-	-
Jan-14	6.26E-04	3.27E-04	9.52E-04	9.52E-04	9.52E-04	-	-	1.27E-03	4.42E-04	2.78E-05	8
Feb-14	-	-	-	-	-	-	-	-	-	-	-
Mar-14	3.92E-03	2.05E-03	0.01	0.01	0.01	-	0.10	0.01	2.78E-03	1.74E-04	52
Apr-14	0.06	0.03	0.10	0.10	0.10	-	0.30	0.13	0.04	2.81E-03	836
May-14	0.09	0.05	0.14	0.14	0.14	-	0.50	0.19	0.07	4.09E-03	1,217
Jun-14	0.11	0.06	0.16	0.16	0.16	-	0.50	0.21	0.07	4.71E-03	1,401
Jul-14	0.07	0.04	0.11	0.11	0.11	-	0.40	0.14	0.05	3.14E-03	935
Aug-14	0.17	0.09	0.26	0.26	0.26	-	0.90	0.34	0.12	0.01	2,219
Sep-14	0.06	0.03	0.09	0.09	0.09	-	0.30	0.12	0.04	2.68E-03	796
Oct-14	0.19	0.10	0.29	0.29	0.29	-	1.00	0.39	0.14	0.01	2,547
Nov-14	0.16	0.09	0.25	0.25	0.25	-	0.90	0.33	0.12	0.01	2,157
Dec-14	-	-	-	-	-	-	-	-	-	-	-
Jan-15	-	-	-	-	-	-	-	-	-	-	-
Feb-15	0.15	0.08	0.23	0.23	0.23	-	0.90	0.31	0.11	0.01	1,996
Mar-15	0.06	0.03	0.09	0.09	0.09	-	0.40	0.12	0.04	2.62E-03	778
Apr-15	-	-	-	-	-	-	-	-	-	-	-
May-15	0.27	0.14	0.41	0.41	0.41	-	1.40	0.54	0.19	0.01	3,518
Jun-15	0.21	0.11	0.32	0.32	0.32	-	1.10	0.43	0.15	0.01	2,792
Jul-15	0.57	0.30	0.87	0.87	0.87	-	2.80	1.16	0.41	0.03	7,577
Aug-15	0.05	0.03	0.08	0.08	0.08	-	0.30	0.11	0.04	2.33E-03	692
Sep-15	0.25	0.13	0.39	0.39	0.39	-	1.20	0.51	0.18	0.01	3,348
Oct-15	0.01	4.03E-03	0.01	0.01	0.01	-	-	0.02	0.01	3.43E-04	102
Nov-15	0.03	0.02	0.05	0.05	0.05	-	0.20	0.06	0.02	1.33E-03	396
Dec-15	-	-	-	-	-	-	-	-	-	-	-
Jan-16	0.32	0.17	0.49	0.49	0.49	-	2.10	0.65	0.23	0.01	4,226
Feb-16	-	-	-	-	-	-	-	-	-	-	-
Mar-16	0.53	0.28	0.81	0.81	0.81	-	2.70	1.08	0.38	0.02	7,047
Apr-16	0.76	0.40	1.16	1.16	1.16	0.10	4.80	1.55	0.54	0.03	10,091
May-16	0.03	0.02	0.05	0.05	0.05	-	0.10	0.06	0.02	1.32E-03	392
Jun-16	0.39	0.20	0.59	0.59	0.59	-	3.40	0.78	0.27	0.02	5,103
Jul-16	0.23	0.12	0.35	0.35	0.35	-	1.30	0.47	0.16	0.01	3,048
Aug-16	0.13	0.07	0.20	0.20	0.20	-	0.70	0.26	0.09	0.01	1,706
Sep-16	0.34	0.18	0.52	0.52	0.52	-	1.90	0.69	0.24	0.02	4,534
Oct-16	0.39	0.21	0.60	0.60	0.60	-	2.30	0.80	0.28	0.02	5,210
Nov-16	0.07	0.03	0.10	0.10	0.10	-	0.40	0.13	0.05	2.94E-03	874
Dec-16	0.05	0.03	0.08	0.08	0.08	-	0.30	0.10	0.03	2.19E-03	652

Table B-8. Historical Actual Monthly Emissions from Combustion Turbine No. 2 (tons/month) [1,2]

	T2 - Combustion Turbine No. 2										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e[3]**
Jan-17	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-
Mar-17	0.32	0.17	0.48	0.48	0.48	-	1.90	0.64	0.22	0.01	4,185
Apr-17	0.42	0.22	0.64	0.64	0.64	-	2.30	0.85	0.30	0.02	5,551
May-17	0.36	0.19	0.54	0.54	0.54	-	2.00	0.72	0.25	0.02	4,707
Jun-17	0.04	0.02	0.07	0.07	0.07	-	0.30	0.09	0.03	1.94E-03	576
Jul-17	0.35	0.18	0.54	0.54	0.54	-	1.90	0.72	0.25	0.02	4,679
Aug-17	0.58	0.30	0.88	0.88	0.88	-	2.90	1.17	0.41	0.03	7,609
Sep-17	0.53	0.27	0.80	0.80	0.80	-	2.80	1.06	0.37	0.02	6,945
Oct-17	0.09	0.05	0.13	0.13	0.13	-	0.50	0.18	0.06	3.92E-03	1,165
Nov-17	0.05	0.03	0.08	0.08	0.08	-	0.30	0.11	0.04	2.39E-03	710
Dec-17	-	-	-	-	-	-	-	-	-	-	-
Jan-18	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-
Mar-18	0.02	0.01	0.04	0.04	0.04	-	0.20	0.05	0.02	1.07E-03	318
Apr-18	0.06	0.03	0.10	0.10	0.10	-	0.40	0.13	0.04	2.81E-03	837
May-18	0.16	0.08	0.24	0.24	0.24	-	0.80	0.32	0.11	0.01	2,104
Jun-18	0.26	0.14	0.40	0.40	0.40	-	1.30	0.53	0.18	0.01	3,449
Jul-18	0.21	0.11	0.31	0.31	0.31	-	1.00	0.42	0.15	0.01	2,714
Aug-18	0.23	0.12	0.35	0.35	0.35	-	1.10	0.46	0.16	0.01	3,031
Sep-18	0.29	0.15	0.44	0.44	0.44	-	1.50	0.59	0.21	0.01	3,859
Oct-18	0.36	0.19	0.54	0.54	0.54	-	1.80	0.72	0.25	0.02	4,706
Nov-18	-	-	-	-	-	-	-	-	-	-	-
Dec-18	0.05	0.03	0.07	0.07	0.07	-	0.30	0.10	0.03	2.16E-03	642
Jan-19	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-
Mar-19	0.01	3.27E-03	0.01	0.01	0.01	-	0.10	0.01	4.43E-03	2.78E-04	83
Apr-19	0.03	0.02	0.05	0.05	0.05	-	0.20	0.06	0.02	1.41E-03	421
May-19	0.10	0.05	0.16	0.16	0.16	-	0.50	0.21	0.07	4.56E-03	1,358
Jun-19	0.16	0.08	0.24	0.24	0.24	-	0.80	0.32	0.11	0.01	2,107
Jul-19	0.64	0.33	0.97	0.97	0.97	-	3.00	1.29	0.45	0.03	8,413
Aug-19	0.53	0.28	0.81	0.81	0.81	-	2.50	1.08	0.38	0.02	7,054
Sep-19	0.79	0.41	1.20	1.20	1.20	0.10	3.90	1.59	0.56	0.03	10,387
Oct-19	0.43	0.22	0.65	0.65	0.65	-	2.10	0.87	0.30	0.02	5,664
Nov-19	0.10	0.05	0.15	0.15	0.15	-	0.60	0.20	0.07	4.39E-03	1,306
Dec-19	4.89E-03	2.55E-03	0.01	0.01	0.01	-	0.10	0.01	3.46E-03	2.17E-04	65
Jan-20	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-
Mar-20	4.89E-03	2.55E-03	0.01	0.01	0.01	-	0.10	0.01	3.46E-03	2.17E-04	65
Apr-20	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.36	0.19	0.55	0.55	0.55	-	1.90	0.73	0.26	0.02	4,770

1. Excluding SO_2 and NO_X, Baseline Emissions calculated as follows:
   Baseline Emissions [ton/month] = Turbine Heat Input [MMBtu/month] x Natural Gas Combustion Emission Factor [lb/MMBtu] / 2,000 [lb/ton]
2. Baseline Emissions of SO_2, NO_X, and CO_2 were obtained from historical data provided by Washington County Power.
3. Baseline emissions of CO_2e are calculated using the historical CO_2 emission data provided by Washington County Power, AP-42 Ch. 3.1, Table 3.1-2a (April 2000) emission factors for CH_4 and N_2O, and global warming potentials for CH_4 and N_2O from 40 CFR 98, Subpart A, Table A-1. The Baseline Emissions for CO_2e were calculated as follows: Baseline Emissions [ton/month] = CO_2 Baseline Emissions [ton/month] + Turbine Heat Input [MMBtu/month] x (CH_4 Emission Factor [lb/MMBtu] x 25 + N_2O Emission Factor [lb/MMBtu] x 298) / 2,000 [lb/ton]

Table B-9. Historical Actual Monthly Emissions from Combustion Turbine No. 3 (tons/month) [1,2]

	T3 - Combustion Turbine No. 3										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e[3]**
Jun-11	0.51	0.27	0.77	0.77	0.77	-	2.20	1.03	0.36	0.02	6,711
Jul-11	0.38	0.20	0.58	0.58	0.58	-	1.70	0.77	0.27	0.02	5,056
Aug-11	0.71	0.37	1.07	1.07	1.07	-	3.20	1.43	0.50	0.03	9,321
Sep-11	0.35	0.18	0.53	0.53	0.53	-	1.50	0.71	0.25	0.02	4,619
Oct-11	0.13	0.07	0.20	0.20	0.20	-	0.60	0.27	0.09	0.01	1,748
Nov-11	0.39	0.21	0.60	0.60	0.60	-	1.80	0.80	0.28	0.02	5,196
Dec-11	0.25	0.13	0.38	0.38	0.38	-	1.20	0.51	0.18	0.01	3,298
Jan-12	0.13	0.07	0.20	0.20	0.20	-	0.70	0.27	0.09	0.01	1,731
Feb-12	0.13	0.07	0.20	0.20	0.20	-	0.70	0.26	0.09	0.01	1,716
Mar-12	0.29	0.15	0.44	0.44	0.44	-	1.20	0.59	0.20	0.01	3,827
Apr-12	0.41	0.21	0.62	0.62	0.62	-	1.70	0.83	0.29	0.02	5,420
May-12	0.42	0.22	0.64	0.64	0.64	-	1.60	0.86	0.30	0.02	5,601
Jun-12	0.86	0.45	1.31	1.31	1.31	0.10	3.60	1.74	0.61	0.04	11,373
Jul-12	1.18	0.61	1.79	1.79	1.79	0.10	4.60	2.38	0.83	0.05	15,544
Aug-12	0.37	0.20	0.57	0.57	0.57	-	1.50	0.76	0.26	0.02	4,944
Sep-12	0.28	0.15	0.43	0.43	0.43	-	1.20	0.58	0.20	0.01	3,763
Oct-12	2.21E-04	1.15E-04	3.36E-04	3.36E-04	3.36E-04	-	-	4.47E-04	1.56E-04	9.80E-06	3
Nov-12	0.04	0.02	0.07	0.07	0.07	-	0.20	0.09	0.03	1.91E-03	568
Dec-12	-	-	-	-	-	-	-	-	-	-	-
Jan-13	-	-	-	-	-	-	-	-	-	-	-
Feb-13	-	-	-	-	-	-	-	-	-	-	-
Mar-13	4.19E-03	2.19E-03	0.01	0.01	0.01	-	0.10	0.01	2.96E-03	1.86E-04	55
Apr-13	0.09	0.05	0.13	0.13	0.13	-	0.40	0.18	0.06	3.94E-03	1,172
May-13	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.06	0.03	0.09	0.09	0.09	-	0.20	0.12	0.04	2.56E-03	760
Jul-13	0.87	0.46	1.33	1.33	1.33	0.10	3.20	1.77	0.62	0.04	11,544
Aug-13	0.05	0.03	0.07	0.07	0.07	-	0.20	0.10	0.03	2.13E-03	634
Sep-13	0.04	0.02	0.06	0.06	0.06	-	0.20	0.08	0.03	1.82E-03	541
Oct-13	0.25	0.13	0.37	0.37	0.37	-	1.10	0.50	0.17	0.01	3,242
Nov-13	0.10	0.05	0.15	0.15	0.15	-	0.40	0.19	0.07	4.25E-03	1,264
Dec-13	-	-	-	-	-	-	-	-	-	-	-
Jan-14	0.01	4.65E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.96E-04	118
Feb-14	0.05	0.02	0.07	0.07	0.07	-	0.20	0.09	0.03	2.06E-03	612
Mar-14	0.01	2.64E-03	0.01	0.01	0.01	-	0.10	0.01	3.58E-03	2.25E-04	67
Apr-14	0.14	0.07	0.21	0.21	0.21	-	0.60	0.28	0.10	0.01	1,852
May-14	0.11	0.06	0.16	0.16	0.16	-	0.50	0.22	0.08	4.78E-03	1,422
Jun-14	0.11	0.06	0.16	0.16	0.16	-	0.40	0.22	0.08	4.74E-03	1,410
Jul-14	0.11	0.06	0.17	0.17	0.17	-	0.50	0.22	0.08	4.86E-03	1,445
Aug-14	0.04	0.02	0.06	0.06	0.06	-	0.20	0.08	0.03	1.82E-03	540
Sep-14	0.06	0.03	0.09	0.09	0.09	-	0.30	0.13	0.04	2.75E-03	818
Oct-14	0.19	0.10	0.30	0.30	0.30	-	0.90	0.39	0.14	0.01	2,565
Nov-14	0.15	0.08	0.23	0.23	0.23	-	0.70	0.30	0.10	0.01	1,958
Dec-14	-	-	-	-	-	-	-	-	-	-	-
Jan-15	0.01	4.71E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	4.01E-04	119
Feb-15	-	-	-	-	-	-	-	-	-	-	-
Mar-15	4.59E-03	2.40E-03	0.01	0.01	0.01	-	0.10	0.01	3.25E-03	2.04E-04	61
Apr-15	-	-	-	-	-	-	-	-	-	-	-
May-15	0.32	0.17	0.49	0.49	0.49	-	1.50	0.65	0.23	0.01	4,259
Jun-15	0.15	0.08	0.23	0.23	0.23	-	0.60	0.31	0.11	0.01	2,008
Jul-15	0.69	0.36	1.06	1.06	1.06	-	3.00	1.41	0.49	0.03	9,176
Aug-15	0.21	0.11	0.32	0.32	0.32	-	0.90	0.43	0.15	0.01	2,815
Sep-15	0.16	0.09	0.25	0.25	0.25	-	0.80	0.33	0.12	0.01	2,153
Oct-15	0.01	3.92E-03	0.01	0.01	0.01	-	-	0.02	0.01	3.33E-04	99
Nov-15	-	-	-	-	-	-	-	-	-	-	-
Dec-15	-	-	-	-	-	-	-	-	-	-	-
Jan-16	0.20	0.10	0.30	0.30	0.30	-	1.10	0.40	0.14	0.01	2,582
Feb-16	-	-	-	-	-	-	-	-	-	-	-
Mar-16	0.32	0.17	0.48	0.48	0.48	-	1.40	0.64	0.22	0.01	4,179
Apr-16	0.71	0.37	1.08	1.08	1.08	-	3.20	1.44	0.50	0.03	9,400
May-16	0.19	0.10	0.28	0.28	0.28	-	0.90	0.38	0.13	0.01	2,473
Jun-16	0.38	0.20	0.58	0.58	0.58	-	1.60	0.78	0.27	0.02	5,069
Jul-16	0.03	0.02	0.05	0.05	0.05	-	0.10	0.07	0.02	1.44E-03	427
Aug-16	-	-	-	-	-	-	-	-	-	-	-
Sep-16	0.25	0.13	0.38	0.38	0.38	-	1.10	0.51	0.18	0.01	3,309
Oct-16	0.19	0.10	0.28	0.28	0.28	-	1.10	0.38	0.13	0.01	2,461
Nov-16	0.08	0.04	0.12	0.12	0.12	-	0.40	0.16	0.05	3.45E-03	1,026
Dec-16	0.05	0.03	0.08	0.08	0.08	-	0.30	0.10	0.04	2.21E-03	657

Table B-9. Historical Actual Monthly Emissions from Combustion Turbine No. 3 (tons/month) [1,2]

	T3 - Combustion Turbine No. 3										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e[3]**
Jan-17	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-
Mar-17	0.10	0.05	0.15	0.15	0.15	-	0.60	0.20	0.07	4.42E-03	1,314
Apr-17	0.42	0.22	0.64	0.64	0.64	-	2.20	0.85	0.30	0.02	5,543
May-17	0.30	0.16	0.45	0.45	0.45	-	1.60	0.60	0.21	0.01	3,933
Jun-17	0.04	0.02	0.05	0.05	0.05	-	0.20	0.07	0.03	1.57E-03	468
Jul-17	0.35	0.18	0.53	0.53	0.53	-	2.70	0.70	0.25	0.02	4,590
Aug-17	0.50	0.26	0.76	0.76	0.76	-	2.40	1.01	0.35	0.02	6,591
Sep-17	0.48	0.25	0.74	0.74	0.74	-	2.50	0.98	0.34	0.02	6,397
Oct-17	4.51E-03	2.36E-03	0.01	0.01	0.01	-	0.10	0.01	3.19E-03	2.01E-04	60
Nov-17	0.05	0.03	0.08	0.08	0.08	-	0.30	0.10	0.04	2.26E-03	672
Dec-17	-	-	-	-	-	-	-	-	-	-	-
Jan-18	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-
Mar-18	0.03	0.01	0.04	0.04	0.04	-	0.20	0.06	0.02	1.25E-03	370
Apr-18	0.18	0.09	0.27	0.27	0.27	-	0.80	0.36	0.13	0.01	2,354
May-18	0.04	0.02	0.07	0.07	0.07	-	0.20	0.09	0.03	1.94E-03	577
Jun-18	0.25	0.13	0.38	0.38	0.38	-	1.20	0.51	0.18	0.01	3,322
Jul-18	0.13	0.07	0.20	0.20	0.20	-	0.60	0.26	0.09	0.01	1,729
Aug-18	0.23	0.12	0.35	0.35	0.35	-	1.10	0.46	0.16	0.01	3,019
Sep-18	0.27	0.14	0.40	0.40	0.40	-	1.30	0.54	0.19	0.01	3,513
Oct-18	0.49	0.26	0.75	0.75	0.75	-	2.50	0.99	0.35	0.02	6,473
Nov-18	-	-	-	-	-	-	-	-	-	-	-
Dec-18	0.05	0.03	0.08	0.08	0.08	-	0.30	0.10	0.04	2.21E-03	658
Jan-19	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-
Mar-19	4.66E-03	2.43E-03	0.01	0.01	0.01	-	-	0.01	3.29E-03	2.07E-04	62
Apr-19	0.03	0.02	0.05	0.05	0.05	-	0.20	0.06	0.02	1.37E-03	408
May-19	0.06	0.03	0.08	0.08	0.08	-	0.30	0.11	0.04	2.46E-03	732
Jun-19	0.16	0.08	0.24	0.24	0.24	-	0.70	0.32	0.11	0.01	2,096
Jul-19	0.62	0.33	0.95	0.95	0.95	-	2.80	1.26	0.44	0.03	8,230
Aug-19	0.53	0.27	0.80	0.80	0.80	-	2.30	1.07	0.37	0.02	6,949
Sep-19	0.77	0.40	1.18	1.18	1.18	0.10	3.70	1.57	0.55	0.03	10,235
Oct-19	0.42	0.22	0.64	0.64	0.64	-	2.00	0.85	0.30	0.02	5,529
Nov-19	0.04	0.02	0.06	0.06	0.06	-	0.30	0.09	0.03	1.88E-03	558
Dec-19	4.64E-03	2.42E-03	0.01	0.01	0.01	-	0.10	0.01	3.28E-03	2.06E-04	61
Jan-20	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-
Mar-20	4.83E-03	2.52E-03	0.01	0.01	0.01	-	-	0.01	3.41E-03	2.15E-04	64
Apr-20	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.27	0.14	0.41	0.41	0.41	-	1.30	0.55	0.19	0.01	3,596

1. Excluding SO_2 and NO_X, Baseline Emissions calculated as follows:
   Baseline Emissions [ton/month] = Turbine Heat Input [MMBtu/month] x Natural Gas Combustion Emission Factor [lb/MMBtu] / 2,000 [lb/ton]
2. Baseline Emissions of SO_2, NO_X, and CO_2 were obtained from historical data provided by Washington County Power.
3. Baseline emissions of CO_2e are calculated using the historical CO_2 emission data provided by Washington County Power, AP-42 Ch. 3.1, Table 3.1-2a (April 2000) emission factors for CH_4 and N_2O, and global warming potentials for CH_4 and N_2O from 40 CFR 98, Subpart A, Table A-1. The Baseline Emissions for CO_2e were calculated as follows: Baseline Emissions [ton/month] = CO_2 Baseline Emissions [ton/month] + Turbine Heat Input [MMBtu/month] x (CH_4 Emission Factor [lb/MMBtu] x 25 + N_2O Emission Factor [lb/MMBtu] x 298) / 2,000 [lb/ton]

Table B-10. Historical Actual Monthly Emissions from Combustion Turbine No. 4 (tons/month) [1,2]

	T4 - Combustion Turbine No. 4										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e^3**
Jun-11	0.50	0.26	0.76	0.76	0.76	-	2.20	1.01	0.35	0.02	6,583
Jul-11	0.27	0.14	0.41	0.41	0.41	-	1.30	0.55	0.19	0.01	3,575
Aug-11	0.50	0.26	0.77	0.77	0.77	-	2.50	1.02	0.36	0.02	6,653
Sep-11	0.10	0.05	0.15	0.15	0.15	-	0.60	0.20	0.07	4.31E-03	1,283
Oct-11	0.01	4.42E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.76E-04	112
Nov-11	-	-	-	-	-	-	-	-	-	-	-
Dec-11	0.09	0.05	0.14	0.14	0.14	-	0.40	0.18	0.06	4.04E-03	1,203
Jan-12	-	-	-	-	-	-	-	-	-	-	-
Feb-12	-	-	-	-	-	-	-	-	-	-	-
Mar-12	-	-	-	-	-	-	-	-	-	-	-
Apr-12	0.46	0.24	0.70	0.70	0.70	-	2.00	0.93	0.33	0.02	6,098
May-12	0.48	0.25	0.72	0.72	0.72	-	1.50	0.96	0.34	0.02	6,280
Jun-12	0.41	0.21	0.62	0.62	0.62	-	1.60	0.82	0.29	0.02	5,363
Jul-12	0.75	0.39	1.14	1.14	1.14	0.10	2.80	1.52	0.53	0.03	9,916
Aug-12	0.18	0.09	0.27	0.27	0.27	-	0.60	0.36	0.13	0.01	2,347
Sep-12	-	-	-	-	-	-	-	-	-	-	-
Oct-12	2.25E-04	1.18E-04	3.43E-04	3.43E-04	3.43E-04	-	-	4.56E-04	1.59E-04	1.00E-05	3
Nov-12	-	-	-	-	-	-	-	-	-	-	-
Dec-12	-	-	-	-	-	-	-	-	-	-	-
Jan-13	-	-	-	-	-	-	-	-	-	-	-
Feb-13	-	-	-	-	-	-	-	-	-	-	-
Mar-13	0.02	0.01	0.02	0.02	0.02	-	0.20	0.03	0.01	6.72E-04	200
Apr-13	0.01	4.32E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.68E-04	110
May-13	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.15	0.08	0.23	0.23	0.23	-	0.60	0.31	0.11	0.01	2,020
Jul-13	1.75	0.91	2.66	2.66	2.66	0.10	6.60	3.55	1.24	0.08	23,134
Aug-13	-	-	-	-	-	-	-	-	-	-	-
Sep-13	-	-	-	-	-	-	-	-	-	-	-
Oct-13	0.01	4.49E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.82E-04	114
Nov-13	-	-	-	-	-	-	-	-	-	-	-
Dec-13	-	-	-	-	-	-	-	-	-	-	-
Jan-14	-	-	-	-	-	-	-	-	-	-	-
Feb-14	-	-	-	-	-	-	-	-	-	-	-
Mar-14	4.50E-03	2.35E-03	0.01	0.01	0.01	-	-	0.01	3.19E-03	2.00E-04	60
Apr-14	-	-	-	-	-	-	-	-	-	-	-
May-14	-	-	-	-	-	-	-	-	-	-	-
Jun-14	0.16	0.09	0.25	0.25	0.25	-	0.60	0.33	0.12	0.01	2,159
Jul-14	-	-	-	-	-	-	-	-	-	-	-
Aug-14	0.14	0.08	0.22	0.22	0.22	-	0.60	0.29	0.10	0.01	1,917
Sep-14	-	-	-	-	-	-	-	-	-	-	-
Oct-14	0.06	0.03	0.10	0.10	0.10	-	0.30	0.13	0.05	2.88E-03	855
Nov-14	0.04	0.02	0.06	0.06	0.06	-	0.20	0.07	0.03	1.62E-03	483
Dec-14	-	-	-	-	-	-	-	-	-	-	-
Jan-15	0.01	4.28E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.64E-04	108
Feb-15	-	-	-	-	-	-	-	-	-	-	-
Mar-15	0.01	4.22E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	3.59E-04	107
Apr-15	-	-	-	-	-	-	-	-	-	-	-
May-15	0.37	0.19	0.56	0.56	0.56	-	1.40	0.74	0.26	0.02	4,849
Jun-15	0.83	0.43	1.26	1.26	1.26	0.10	3.20	1.67	0.58	0.04	10,921
Jul-15	0.97	0.51	1.47	1.47	1.47	0.10	3.80	1.96	0.68	0.04	12,794
Aug-15	-	-	-	-	-	-	-	-	-	-	-
Sep-15	0.17	0.09	0.25	0.25	0.25	-	0.50	0.34	0.12	0.01	2,203
Oct-15	0.01	3.83E-03	0.01	0.01	0.01	-	0.10	0.01	0.01	3.26E-04	97
Nov-15	0.46	0.24	0.69	0.69	0.69	-	1.60	0.92	0.32	0.02	6,026
Dec-15	-	-	-	-	-	-	-	-	-	-	-
Jan-16	-	-	-	-	-	-	-	-	-	-	-
Feb-16	-	-	-	-	-	-	-	-	-	-	-
Mar-16	3.84E-03	2.01E-03	0.01	0.01	0.01	-	0.10	0.01	2.72E-03	1.71E-04	51
Apr-16	-	-	-	-	-	-	-	-	-	-	-
May-16	0.07	0.04	0.11	0.11	0.11	-	0.20	0.14	0.05	3.17E-03	942
Jun-16	0.10	0.05	0.16	0.16	0.16	-	0.40	0.21	0.07	4.58E-03	1,362
Jul-16	0.19	0.10	0.28	0.28	0.28	-	0.60	0.38	0.13	0.01	2,458
Aug-16	-	-	-	-	-	-	-	-	-	-	-
Sep-16	-	-	-	-	-	-	-	-	-	-	-
Oct-16	0.08	0.04	0.12	0.12	0.12	-	0.30	0.16	0.06	3.46E-03	1,031
Nov-16	-	-	-	-	-	-	-	-	-	-	-
Dec-16	-	-	-	-	-	-	-	-	-	-	-

Table B-10. Historical Actual Monthly Emissions from Combustion Turbine No. 4 (tons/month) [1,2]

	T4 - Combustion Turbine No. 4										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e[3]**
Jan-17	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-
Mar-17	0.01	2.67E-03	0.01	0.01	0.01	-	0.10	0.01	3.62E-03	2.27E-04	68
Apr-17	-	-	-	-	-	-	-	-	-	-	-
May-17	0.09	0.05	0.13	0.13	0.13	-	0.30	0.18	0.06	3.87E-03	1,150
Jun-17	-	-	-	-	-	-	-	-	-	-	-
Jul-17	0.26	0.14	0.39	0.39	0.39	-	0.80	0.52	0.18	0.01	3,425
Aug-17	-	-	-	-	-	-	-	-	-	-	-
Sep-17	-	-	-	-	-	-	-	-	-	-	-
Oct-17	4.55E-03	2.38E-03	0.01	0.01	0.01	-	0.10	0.01	3.22E-03	2.02E-04	60
Nov-17	-	-	-	-	-	-	-	-	-	-	-
Dec-17	-	-	-	-	-	-	-	-	-	-	-
Jan-18	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-
Mar-18	4.18E-03	2.18E-03	0.01	0.01	0.01	-	0.10	0.01	2.96E-03	1.86E-04	55
Apr-18	-	-	-	-	-	-	-	-	-	-	-
May-18	0.29	0.15	0.45	0.45	0.45	-	1.10	0.59	0.21	0.01	3,865
Jun-18	0.53	0.28	0.80	0.80	0.80	-	1.50	1.07	0.37	0.02	6,991
Jul-18	-	-	-	-	-	-	-	-	-	-	-
Aug-18	-	-	-	-	-	-	-	-	-	-	-
Sep-18	0.27	0.14	0.42	0.42	0.42	-	0.90	0.55	0.19	0.01	3,612
Oct-18	0.24	0.13	0.37	0.37	0.37	-	0.70	0.49	0.17	0.01	3,188
Nov-18	-	-	-	-	-	-	-	-	-	-	-
Dec-18	-	-	-	-	-	-	-	-	-	-	-
Jan-19	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-
Mar-19	4.83E-03	2.52E-03	0.01	0.01	0.01	-	-	0.01	3.41E-03	2.15E-04	64
Apr-19	-	-	-	-	-	-	-	-	-	-	-
May-19	-	-	-	-	-	-	-	-	-	-	-
Jun-19	0.23	0.12	0.35	0.35	0.35	-	0.60	0.47	0.16	0.01	3,083
Jul-19	0.86	0.45	1.31	1.31	1.31	0.10	2.50	1.75	0.61	0.04	11,419
Aug-19	-	-	-	-	-	-	-	-	-	-	-
Sep-19	1.12	0.59	1.71	1.71	1.71	0.10	3.30	2.27	0.79	0.05	14,841
Oct-19	0.47	0.25	0.72	0.72	0.72	-	1.50	0.95	0.33	0.02	6,228
Nov-19	-	-	-	-	-	-	-	-	-	-	-
Dec-19	4.75E-03	2.48E-03	0.01	0.01	0.01	-	0.10	0.01	3.36E-03	2.11E-04	63
Jan-20	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-
Mar-20	4.40E-03	2.30E-03	0.01	0.01	0.01	-	0.10	0.01	3.11E-03	1.95E-04	58
Apr-20	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.06	0.03	0.09	0.09	0.09	-	0.20	0.12	0.04	2.63E-03	784

1. Excluding SO_2 and NO_X, Baseline Emissions calculated as follows:
   Baseline Emissions [ton/month] = Turbine Heat Input [MMBtu/month] x Natural Gas Combustion Emission Factor [lb/MMBtu] / 2,000 [lb/ton]
2. Baseline Emissions of SO_2, NO_X, and CO_2 were obtained from historical data provided by Washington County Power.
3. Baseline emissions of CO_2e are calculated using the historical CO_2 emission data provided by Washington County Power, AP-42 Ch. 3.1, Table 3.1-2a (April 2000) emission factors for CH_4 and N_2O, and global warming potentials for CH_4 and N_2O from 40 CFR 98, Subpart A, Table A-1. The Baseline Emissions for CO_2e were calculated as follows: Baseline Emissions [ton/month] = CO_2 Baseline Emissions [ton/month] + Turbine Heat Input [MMBtu/month] x (CH_4 Emission Factor [lb/MMBtu] x 25 + N_2O Emission Factor [lb/MMBtu] x 298) / 2,000 [lb/ton]

Table B-11. Historical Actual Monthly Emissions from Turbines (tons/month)

	Combustion Turbine Nos. 1 - 4										
Month	Filterable PM	Condensable PM	Total PM	Total PM_{10}	Total $PM_{2.5}$	SO_2	NO_X	CO	VOC	Sulfuric Acid Mist (H_2SO_4)	CO_2e
Jun-11	1.92	1.00	2.92	2.92	2.92	-	9.00	3.89	1.36	0.09	25,366
Jul-11	1.34	0.70	2.04	2.04	2.04	-	6.40	2.71	0.95	0.06	17,698
Aug-11	2.31	1.21	3.52	3.52	3.52	-	11.40	4.68	1.63	0.10	30,558
Sep-11	0.87	0.46	1.33	1.33	1.33	-	4.30	1.77	0.62	0.04	11,559
Oct-11	0.26	0.14	0.40	0.40	0.40	-	1.50	0.53	0.19	0.01	3,465
Nov-11	0.70	0.36	1.06	1.06	1.06	-	3.40	1.41	0.49	0.03	9,202
Dec-11	0.70	0.37	1.07	1.07	1.07	-	3.60	1.42	0.50	0.03	9,287
Jan-12	0.25	0.13	0.38	0.38	0.38	-	1.40	0.50	0.18	0.01	3,288
Feb-12	0.26	0.14	0.40	0.40	0.40	-	1.50	0.53	0.18	0.01	3,450
Mar-12	1.14	0.59	1.73	1.73	1.73	-	5.50	2.30	0.80	0.05	15,023
Apr-12	2.74	1.43	4.18	4.18	4.18	0.10	11.20	5.56	1.94	0.12	36,270
May-12	1.91	1.00	2.90	2.90	2.90	-	7.20	3.87	1.35	0.08	25,222
Jun-12	1.86	0.97	2.82	2.82	2.82	0.10	7.90	3.76	1.31	0.08	24,534
Jul-12	3.27	1.71	4.98	4.98	4.98	0.30	13.00	6.62	2.31	0.15	43,225
Aug-12	0.95	0.49	1.44	1.44	1.44	-	3.90	1.92	0.67	0.04	12,526
Sep-12	0.48	0.25	0.73	0.73	0.73	-	2.10	0.97	0.34	0.02	6,335
Oct-12	8.78E-04	4.58E-04	1.34E-03	1.34E-03	1.34E-03	-	-	1.78E-03	6.21E-04	3.90E-05	12
Nov-12	0.18	0.10	0.28	0.28	0.28	-	0.90	0.37	0.13	0.01	2,412
Dec-12	-	-	-	-	-	-	-	-	-	-	-
Jan-13	0.01	4.80E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	4.08E-04	121
Feb-13	-	-	-	-	-	-	-	-	-	-	-
Mar-13	0.03	0.02	0.04	0.04	0.04	-	0.50	0.06	0.02	1.30E-03	386
Apr-13	0.36	0.19	0.55	0.55	0.55	-	1.80	0.74	0.26	0.02	4,798
May-13	-	-	-	-	-	-	-	-	-	-	-
Jun-13	0.46	0.24	0.70	0.70	0.70	-	1.90	0.93	0.33	0.02	6,089
Jul-13	4.42	2.31	6.72	6.72	6.72	0.30	16.90	8.95	3.12	0.20	58,378
Aug-13	0.10	0.05	0.15	0.15	0.15	-	0.40	0.20	0.07	4.29E-03	1,277
Sep-13	0.14	0.07	0.21	0.21	0.21	-	0.70	0.29	0.10	0.01	1,864
Oct-13	0.52	0.27	0.79	0.79	0.79	-	2.50	1.05	0.37	0.02	6,823
Nov-13	0.27	0.14	0.41	0.41	0.41	-	1.20	0.55	0.19	0.01	3,589
Dec-13	-	-	-	-	-	-	-	-	-	-	-
Jan-14	0.01	4.97E-03	0.01	0.01	0.01	-	0.10	0.02	0.01	4.23E-04	126
Feb-14	0.05	0.02	0.07	0.07	0.07	-	0.20	0.09	0.03	2.06E-03	612
Mar-14	0.14	0.08	0.22	0.22	0.22	-	0.80	0.29	0.10	0.01	1,913
Apr-14	0.20	0.11	0.31	0.31	0.31	-	0.90	0.41	0.14	0.01	2,689
May-14	0.20	0.10	0.30	0.30	0.30	-	1.00	0.40	0.14	0.01	2,639
Jun-14	0.43	0.23	0.66	0.66	0.66	-	1.70	0.88	0.31	0.02	5,749
Jul-14	0.18	0.09	0.27	0.27	0.27	-	0.90	0.36	0.13	0.01	2,380
Aug-14	0.50	0.26	0.76	0.76	0.76	-	2.30	1.01	0.35	0.02	6,610
Sep-14	0.20	0.11	0.31	0.31	0.31	-	0.90	0.41	0.14	0.01	2,685
Oct-14	0.52	0.27	0.79	0.79	0.79	-	2.50	1.05	0.37	0.02	6,825
Nov-14	0.41	0.21	0.62	0.62	0.62	-	2.10	0.83	0.29	0.02	5,428
Dec-14	-	-	-	-	-	-	-	-	-	-	-
Jan-15	0.02	0.01	0.03	0.03	0.03	-	0.20	0.03	0.01	7.65E-04	228
Feb-15	0.15	0.08	0.23	0.23	0.23	-	0.90	0.31	0.11	0.01	1,996
Mar-15	0.08	0.04	0.12	0.12	0.12	-	0.70	0.16	0.06	3.53E-03	1,050
Apr-15	-	-	-	-	-	-	-	-	-	-	-
May-15	1.32	0.69	2.01	2.01	2.01	-	5.70	2.68	0.93	0.06	17,470
Jun-15	2.03	1.06	3.09	3.09	3.09	0.20	8.00	4.11	1.43	0.09	26,821
Jul-15	3.30	1.72	5.02	5.02	5.02	0.20	13.70	6.68	2.33	0.15	43,596
Aug-15	0.35	0.18	0.53	0.53	0.53	-	1.50	0.71	0.25	0.02	4,645
Sep-15	0.93	0.48	1.41	1.41	1.41	-	3.70	1.88	0.66	0.04	12,257
Oct-15	0.10	0.05	0.14	0.14	0.14	-	0.40	0.19	0.07	4.23E-03	1,258
Nov-15	1.01	0.53	1.53	1.53	1.53	-	3.70	2.04	0.71	0.04	13,299
Dec-15	-	-	-	-	-	-	-	-	-	-	-
Jan-16	0.51	0.27	0.78	0.78	0.78	-	3.20	1.04	0.36	0.02	6,808
Feb-16	-	-	-	-	-	-	-	-	-	-	-
Mar-16	0.86	0.45	1.31	1.31	1.31	-	4.30	1.74	0.61	0.04	11,373
Apr-16	1.47	0.77	2.24	2.24	2.24	0.10	8.00	2.99	1.04	0.07	19,491
May-16	0.29	0.15	0.44	0.44	0.44	-	1.20	0.58	0.20	0.01	3,807
Jun-16	1.02	0.53	1.55	1.55	1.55	-	5.90	2.06	0.72	0.05	13,451
Jul-16	0.45	0.23	0.68	0.68	0.68	-	2.00	0.91	0.32	0.02	5,933
Aug-16	0.13	0.07	0.20	0.20	0.20	-	0.70	0.26	0.09	0.01	1,706
Sep-16	0.59	0.31	0.90	0.90	0.90	-	3.00	1.20	0.42	0.03	7,843
Oct-16	0.74	0.39	1.12	1.12	1.12	-	4.00	1.49	0.52	0.03	9,752
Nov-16	0.14	0.08	0.22	0.22	0.22	-	0.80	0.29	0.10	0.01	1,900
Dec-16	0.10	0.05	0.15	0.15	0.15	-	0.60	0.20	0.07	4.40E-03	1,310

Table B-11. Historical Actual Monthly Emissions from Turbines (tons/month)

	Combustion Turbine Nos. 1 - 4										
Month	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e**
Jan-17	-	-	-	-	-	-	-	-	-	-	-
Feb-17	-	-	-	-	-	-	-	-	-	-	-
Mar-17	0.42	0.22	0.65	0.65	0.65	-	2.60	0.86	0.30	0.02	5,618
Apr-17	0.84	0.44	1.28	1.28	1.28	-	4.50	1.70	0.59	0.04	11,094
May-17	0.83	0.43	1.26	1.26	1.26	-	4.30	1.68	0.59	0.04	10,937
Jun-17	0.08	0.04	0.12	0.12	0.12	-	0.50	0.16	0.06	3.51E-03	1,044
Jul-17	1.22	0.64	1.85	1.85	1.85	-	6.40	2.47	0.86	0.05	16,090
Aug-17	1.07	0.56	1.64	1.64	1.64	-	5.30	2.18	0.76	0.05	14,200
Sep-17	1.01	0.53	1.54	1.54	1.54	-	5.30	2.04	0.71	0.04	13,343
Oct-17	0.10	0.05	0.16	0.16	0.16	-	0.80	0.21	0.07	4.54E-03	1,351
Nov-17	0.10	0.05	0.16	0.16	0.16	-	0.60	0.21	0.07	4.65E-03	1,382
Dec-17	-	-	-	-	-	-	-	-	-	-	-
Jan-18	-	-	-	-	-	-	-	-	-	-	-
Feb-18	-	-	-	-	-	-	-	-	-	-	-
Mar-18	0.06	0.03	0.09	0.09	0.09	-	0.50	0.12	0.04	2.72E-03	808
Apr-18	0.24	0.13	0.37	0.37	0.37	-	1.20	0.49	0.17	0.01	3,190
May-18	0.67	0.35	1.02	1.02	1.02	-	2.90	1.36	0.48	0.03	8,886
Jun-18	1.47	0.77	2.24	2.24	2.24	-	5.50	2.98	1.04	0.07	19,413
Jul-18	0.42	0.22	0.63	0.63	0.63	-	1.90	0.84	0.29	0.02	5,513
Aug-18	0.46	0.24	0.70	0.70	0.70	-	2.20	0.93	0.32	0.02	6,049
Sep-18	0.98	0.51	1.50	1.50	1.50	-	4.30	1.99	0.69	0.04	12,990
Oct-18	1.21	0.63	1.84	1.84	1.84	-	5.50	2.45	0.86	0.05	15,986
Nov-18	-	-	-	-	-	-	-	-	-	-	-
Dec-18	0.10	0.05	0.15	0.15	0.15	-	0.60	0.20	0.07	4.37E-03	1,300
Jan-19	-	-	-	-	-	-	-	-	-	-	-
Feb-19	-	-	-	-	-	-	-	-	-	-	-
Mar-19	0.02	0.01	0.03	0.03	0.03	-	0.10	0.04	0.01	8.96E-04	266
Apr-19	0.06	0.03	0.10	0.10	0.10	-	0.40	0.13	0.04	2.79E-03	829
May-19	0.31	0.16	0.48	0.48	0.48	-	1.40	0.64	0.22	0.01	4,149
Jun-19	0.90	0.47	1.37	1.37	1.37	-	3.30	1.82	0.64	0.04	11,900
Jul-19	2.29	1.20	3.49	3.49	3.49	0.10	8.90	4.64	1.62	0.10	30,277
Aug-19	1.53	0.80	2.33	2.33	2.33	-	6.40	3.10	1.08	0.07	20,196
Sep-19	3.66	1.91	5.58	5.58	5.58	0.40	14.70	7.42	2.59	0.16	48,425
Oct-19	1.70	0.89	2.59	2.59	2.59	-	7.10	3.45	1.20	0.08	22,512
Nov-19	0.14	0.07	0.21	0.21	0.21	-	0.90	0.29	0.10	0.01	1,864
Dec-19	0.02	0.01	0.03	0.03	0.03	-	0.40	0.04	0.01	8.25E-04	245
Jan-20	-	-	-	-	-	-	-	-	-	-	-
Feb-20	-	-	-	-	-	-	-	-	-	-	-
Mar-20	0.20	0.11	0.31	0.31	0.31	-	1.00	0.41	0.14	0.01	2,665
Apr-20	-	-	-	-	-	-	-	-	-	-	-
May-20	-	-	-	-	-	-	-	-	-	-	-
Jun-20	0.80	0.42	1.22	1.22	1.22	-	3.80	1.63	0.57	0.04	10,614

Table B-12. Selection of Baseline (tpy)[1]

			Combustion Turbine Baseline Emissions										
Start Month		**End Month**	**Filterable PM**	**Condensable PM**	**Total PM**	**Total PM_{10}**	**Total $PM_{2.5}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Sulfuric Acid Mist (H_2SO_4)**	**CO_2e**
Jun-11	-	May-13	10.77	5.62	16.39	16.39	16.39	0.25	48.30	21.82	7.62	0.48	142,369
Jul-11	-	Jun-13	10.04	5.24	15.28	15.28	15.28	0.25	44.75	20.34	7.10	0.45	132,730
Aug-11	-	Jul-13	11.58	6.05	17.63	17.63	17.63	0.40	50.00	23.46	8.19	0.51	153,070
Sep-11	-	Aug-13	10.47	5.47	15.94	15.94	15.94	0.40	44.50	21.21	7.41	0.47	138,429
Oct-11	-	Sep-13	10.10	5.28	15.38	15.38	15.38	0.40	42.70	20.47	7.15	0.45	133,582
Nov-11	-	Oct-13	10.23	5.34	15.57	15.57	15.57	0.40	43.20	20.73	7.24	0.45	135,261
Dec-11	-	Nov-13	10.02	5.23	15.25	15.25	15.25	0.40	42.10	20.30	7.09	0.45	132,455
Jan-12	-	Dec-13	9.67	5.05	14.72	14.72	14.72	0.40	40.30	19.59	6.84	0.43	127,811
Feb-12	-	Jan-14	9.55	4.99	14.53	14.53	14.53	0.40	39.65	19.35	6.75	0.42	126,230
Mar-12	-	Feb-14	9.44	4.93	14.37	14.37	14.37	0.40	39.00	19.13	6.68	0.42	124,811
Apr-12	-	Mar-14	8.95	4.67	13.62	13.62	13.62	0.40	36.65	18.12	6.33	0.40	118,256
May-12	-	Apr-14	7.68	4.01	11.68	11.68	11.68	0.35	31.50	15.55	5.43	0.34	101,465
Jun-12	-	May-14	6.82	3.56	10.38	10.38	10.38	0.35	28.40	13.82	4.82	0.30	90,174
Jul-12	-	Jun-14	6.11	3.19	9.30	9.30	9.30	0.30	25.30	12.38	4.32	0.27	80,781
Aug-12	-	Jul-14	4.57	2.38	6.95	6.95	6.95	0.15	19.25	9.25	3.23	0.20	60,359
Sep-12	-	Aug-14	4.34	2.27	6.61	6.61	6.61	0.15	18.45	8.80	3.07	0.19	57,401
Oct-12	-	Sep-14	4.20	2.20	6.40	6.40	6.40	0.15	17.85	8.52	2.97	0.19	55,576
Nov-12	-	Oct-14	4.46	2.33	6.79	6.79	6.79	0.15	19.10	9.04	3.16	0.20	58,983
Dec-12	-	Nov-14	4.58	2.39	6.97	6.97	6.97	0.15	19.70	9.27	3.24	0.20	60,490
Jan-13	-	Dec-14	4.58	2.39	6.97	6.97	6.97	0.15	19.70	9.27	3.24	0.20	60,490
Feb-13	-	Jan-15	4.58	2.39	6.97	6.97	6.97	0.15	19.75	9.28	3.24	0.20	60,543
Mar-13	-	Feb-15	4.66	2.43	7.09	7.09	7.09	0.15	20.20	9.43	3.29	0.21	61,541
Apr-13	-	Mar-15	4.68	2.44	7.12	7.12	7.12	0.15	20.30	9.48	3.31	0.21	61,873
May-13	-	Apr-15	4.50	2.35	6.85	6.85	6.85	0.15	19.40	9.11	3.18	0.20	59,474
Jun-13	-	May-15	5.16	2.69	7.85	7.85	7.85	0.15	22.25	10.45	3.65	0.23	68,209
Jul-13	-	Jun-15	5.94	3.10	9.05	9.05	9.05	0.25	25.30	12.04	4.20	0.26	78,575
Aug-13	-	Jul-15	5.38	2.81	8.20	8.20	8.20	0.20	23.70	10.91	3.81	0.24	71,184
Sep-13	-	Aug-15	5.51	2.88	8.39	8.39	8.39	0.20	24.25	11.17	3.90	0.24	72,868
Oct-13	-	Sep-15	5.91	3.08	8.99	8.99	8.99	0.20	25.75	11.96	4.18	0.26	78,065
Nov-13	-	Oct-15	5.69	2.97	8.67	8.67	8.67	0.20	24.70	11.54	4.03	0.25	75,282
Dec-13	-	Nov-15	6.06	3.17	9.23	9.23	9.23	0.20	25.95	12.28	4.29	0.27	80,137
Jan-14	-	Dec-15	6.06	3.17	9.23	9.23	9.23	0.20	25.95	12.28	4.29	0.27	80,137
Feb-14	-	Jan-16	6.31	3.30	9.61	9.61	9.61	0.20	27.50	12.79	4.47	0.28	83,478
Mar-14	-	Feb-16	6.29	3.29	9.58	9.58	9.58	0.20	27.40	12.75	4.45	0.28	83,172
Apr-14	-	Mar-16	6.65	3.47	10.12	10.12	10.12	0.20	29.15	13.47	4.70	0.30	87,902
May-14	-	Apr-16	7.28	3.80	11.09	11.09	11.09	0.25	32.70	14.76	5.15	0.32	96,304
Jun-14	-	May-16	7.33	3.83	11.16	11.16	11.16	0.25	32.80	14.85	5.18	0.33	96,888
Jul-14	-	Jun-16	7.62	3.98	11.60	11.60	11.60	0.25	34.90	15.44	5.39	0.34	100,739
Aug-14	-	Jul-16	7.75	4.05	11.80	11.80	11.80	0.25	35.45	15.71	5.48	0.34	102,515
Sep-14	-	Aug-16	7.57	3.95	11.52	11.52	11.52	0.25	34.65	15.33	5.35	0.34	100,063
Oct-14	-	Sep-16	7.76	4.05	11.82	11.82	11.82	0.25	35.70	15.73	5.49	0.35	102,642
Nov-14	-	Oct-16	7.87	4.11	11.99	11.99	11.99	0.25	36.45	15.95	5.57	0.35	104,106
Dec-14	-	Nov-16	7.74	4.04	11.78	11.78	11.78	0.25	35.80	15.68	5.48	0.34	102,342
Jan-15	-	Dec-16	7.79	4.07	11.86	11.86	11.86	0.25	36.10	15.78	5.51	0.35	102,997
Feb-15	-	Jan-17	7.78	4.06	11.85	11.85	11.85	0.25	36.00	15.77	5.50	0.35	102,883
Mar-15	-	Feb-17	7.71	4.02	11.73	11.73	11.73	0.25	35.55	15.61	5.45	0.34	101,885
Apr-15	-	Mar-17	7.88	4.11	11.99	11.99	11.99	0.25	36.50	15.96	5.57	0.35	104,169
May-15	-	Apr-17	8.30	4.33	12.63	12.63	12.63	0.25	38.75	16.81	5.87	0.37	109,716
Jun-15	-	May-17	8.05	4.21	12.26	12.26	12.26	0.25	38.05	16.31	5.69	0.36	106,449
Jul-15	-	Jun-17	7.08	3.70	10.77	10.77	10.77	0.15	34.30	14.34	5.01	0.31	93,561
Aug-15	-	Jul-17	6.04	3.15	9.19	9.19	9.19	0.05	30.65	12.23	4.27	0.27	79,808
Sep-15	-	Aug-17	6.40	3.34	9.74	9.74	9.74	0.05	32.55	12.96	4.53	0.28	84,585
Oct-15	-	Sep-17	6.44	3.36	9.80	9.80	9.80	0.05	33.35	13.05	4.55	0.29	85,128
Nov-15	-	Oct-17	6.44	3.36	9.81	9.81	9.81	0.05	33.55	13.05	4.56	0.29	85,175
Dec-15	-	Nov-17	5.99	3.13	9.12	9.12	9.12	0.05	32.00	12.14	4.24	0.27	79,216
Jan-16	-	Dec-17	5.99	3.13	9.12	9.12	9.12	0.05	32.00	12.14	4.24	0.27	79,216
Feb-16	-	Jan-18	5.73	2.99	8.73	8.73	8.73	0.05	30.40	11.62	4.06	0.25	75,813
Mar-16	-	Feb-18	5.73	2.99	8.73	8.73	8.73	0.05	30.40	11.62	4.06	0.25	75,813
Apr-16	-	Mar-18	5.34	2.79	8.12	8.12	8.12	0.05	28.50	10.81	3.77	0.24	70,530
May-16	-	Apr-18	4.72	2.46	7.18	7.18	7.18	0.00	25.10	9.56	3.34	0.21	62,380
Jun-16	-	May-18	4.91	2.56	7.48	7.48	7.48	0.00	25.95	9.95	3.47	0.22	64,919
Jul-16	-	Jun-18	5.14	2.68	7.82	7.82	7.82	0.00	25.75	10.41	3.63	0.23	67,901
Aug-16	-	Jul-18	5.12	2.67	7.79	7.79	7.79	0.00	25.70	10.37	3.62	0.23	67,690
Sep-16	-	Aug-18	5.28	2.76	8.04	8.04	8.04	0.00	26.45	10.71	3.74	0.23	69,862
Oct-16	-	Sep-18	5.48	2.86	8.34	8.34	8.34	0.00	27.10	11.10	3.88	0.24	72,436
Nov-16	-	Oct-18	5.72	2.98	8.70	8.70	8.70	0.00	27.85	11.58	4.04	0.25	75,553
Dec-16	-	Nov-18	5.64	2.95	8.59	8.59	8.59	0.00	27.45	11.43	3.99	0.25	74,603
Jan-17	-	Dec-18	5.64	2.95	8.59	8.59	8.59	0.00	27.45	11.43	3.99	0.25	74,598
Feb-17	-	Jan-19	5.64	2.95	8.59	8.59	8.59	0.00	27.45	11.43	3.99	0.25	74,598
Mar-17	-	Feb-19	5.64	2.95	8.59	8.59	8.59	0.00	27.45	11.43	3.99	0.25	74,598
Apr-17	-	Mar-19	5.44	2.84	8.28	8.28	8.28	0.00	26.20	11.02	3.85	0.24	71,922
May-17	-	Apr-19	5.05	2.64	7.69	7.69	7.69	0.00	24.15	10.24	3.57	0.22	66,789
Jun-17	-	May-19	4.80	2.50	7.30	7.30	7.30	0.00	22.70	9.72	3.39	0.21	63,395
Jul-17	-	Jun-19	5.21	2.72	7.92	7.92	7.92	0.00	24.10	10.55	3.68	0.23	68,823
Aug-17	-	Jul-19	5.74	3.00	8.74	8.74	8.74	0.05	25.35	11.63	4.06	0.26	75,917
Sep-17	-	Aug-19	5.97	3.12	9.09	9.09	9.09	0.05	25.90	12.09	4.22	0.27	78,915
Oct-17	-	Sep-19	7.30	3.81	11.11	11.11	11.11	0.25	30.60	14.78	5.16	0.32	96,456
Nov-17	-	Oct-19	8.10	4.23	12.32	12.32	12.32	0.25	33.75	16.40	5.73	0.36	107,036
Dec-17	-	Nov-19	8.11	4.24	12.35	12.35	12.35	0.25	33.90	16.44	5.74	0.36	107,277
Jan-18	-	Dec-19	8.12	4.24	12.37	12.37	12.37	0.25	34.10	16.46	5.75	0.36	107,400
Feb-18	-	Jan-20	8.12	4.24	12.37	12.37	12.37	0.25	34.10	16.46	5.75	0.36	107,400
Mar-18	-	Feb-20	8.12	4.24	12.37	12.37	12.37	0.25	34.10	16.46	5.75	0.36	107,400
Apr-18	-	Mar-20	8.19	4.28	12.47	12.47	12.47	0.25	34.35	16.60	5.80	0.36	108,328
May-18	-	Apr-20	8.07	4.22	12.29	12.29	12.29	0.25	33.75	16.36	5.71	0.36	106,733
Jun-18	-	May-20	7.74	4.04	11.78	11.78	11.78	0.25	32.30	15.68	5.47	0.34	102,290
Jul-18	-	Jun-20	7.40	3.87	11.27	11.27	11.27	0.25	31.45	15.00	5.24	0.33	97,890
Max Annual Baseline Emissions:			**11.58**	**6.05**	**17.63**	**17.63**	**17.63**	**0.40**	**50.00**	**23.46**	**8.19**	**0.51**	**153,070**
Period Start:			**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**	**Aug-11**
Period End:			**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**	**Jul-13**

1. Annual baseline emissions are estimated from Table B-11 and represent the sum of the total emissions during the 24-month baseline period divided by 2.

Table B-13. Projected Actual Emissions from Turbines Nos. 1 - 4

Pollutant	T1 - Combustion Turbine No. 1 (tpy)	T2 - Combustion Turbine No. 2 (tpy)	T3 - Combustion Turbine No. 3 (tpy)	T4 - Combustion Turbine No. 4 (tpy)	Projected Actual Turbine Emissions (tpy)
SO_2	2.30	2.30	2.30	2.30	9.19
NO_X	152.73	152.73	152.73	152.73	610.94
CO	70.86	70.86	70.86	70.86	283.44
Total PM	43.00	43.00	43.00	43.00	172.00
Filterable PM	27.15	27.15	27.15	27.15	108.59
Condensable PM	15.85	15.85	15.85	15.85	63.41
Total PM_{10}	43.00	43.00	43.00	43.00	172.00
Total $PM_{2.5}$	43.00	43.00	43.00	43.00	172.00
VOC	25.61	25.61	25.61	25.61	102.45
Lead	0.01	0.01	0.01	0.01	0.03
Sulfuric Acid Mist (H_2SO_4)	1.07	1.07	1.07	1.07	4.26
CO_2e	387,496	387,496	387,496	387,496	1,549,985

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr	
Operating Hours	2,700	hrs/yr	NOx, CO, VOC
	3000	hrs/yr	Other Pollutants

Table B-14. Projected Actual Criteria Pollutant Emissions from Turbine No. 1 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	6.00E-04	1.06	1.59
NO_X	3.00E-02	52.89	71.41
CO	1.82E-02	32.20	43.47
Total PM	1.37E-02	24.19	36.29
Filterable PM	9.00E-03	15.89	23.84
Condensable PM	4.70E-03	8.30	12.45
Total PM_{10}	1.37E-02	24.19	36.29
Total $PM_{2.5}$	1.37E-02	24.19	36.29
VOC	6.37E-03	11.24	15.17
Sulfuric Acid Mist (H_2SO_4)	4.00E-04	0.71	1.06
GHGs			
CO_2	116.98	206,580	309,870
CH_4	2.20E-03	3.89	5.84
N_2O	2.20E-04	0.39	0.58
CO_2e	117.10	206,793	310,190

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr	
Turbine Operating Hours	450	hrs/yr	NOx, CO, VOC
	500	hrs/yr	Other Pollutants

Table B-15. Projected Actual Criteria Pollutant Emissions from Turbine No. 1 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	1.50E-03	2.84	0.71
NO_X	1.40E-01	264.12	59.43
CO	4.05E-02	76.57	17.23
Total PM	1.42E-02	26.84	6.71
Filterable PM	7.00E-03	13.23	3.31
Condensable PM	7.20E-03	13.61	3.40
Total PM_{10}	1.42E-02	26.838	6.71
Total $PM_{2.5}$	1.42E-02	26.84	6.71
VOC	1.59E-02	30.07	6.77
Sulfuric Acid Mist (H_2SO_4)	1.40E-05	0.03	0.01
GHGs			
CO_2	163.05	308,169	77,042
CH_4	6.61E-03	12.50	3.13
N_2O	1.32E-03	2.50	0.63
CO_2e	163.61	309,226	77,307

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Startup/Shutdown Operating Parameters

Heat Input Natural Gas SUSD Hour	1,478	MMBtu/hr
Hours of Natural Gas SUSD	300	hrs/yr
Heat Input Fuel Oil SUSD Hour	1,582	MMBtu/hr
Hours of Fuel Oil SUSD	50	hrs/yr

Table B-16. Projected Actual Emissions from Turbine No. 1 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/MMBtu)	Operation Hours/ Events[2]	Potential Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	264.12	130.83
CO	--	--	76.57	60.70
VOC	--	--	30.07	21.94
Startup/Shutdown Period Natural Gas				
NO_X	0.0539	300 hrs natural gas	79.68	11.95
CO	0.0328		48.51	7.28
VOC	0.0115		16.93	2.54
Startup/Shutdown Period Fuel Oil				
NO_X	0.25	50 hrs fuel oil	397.94	9.95
CO	0.0729		115.36	2.88
VOC	0.03		45.30	1.13
Annual Emissions[5]				
NO_X	--	--	--	152.73
CO	--	--	--	70.86
VOC	--	--	--	25.61

1. Startup/shutdown emission factors based on engineering analysis of available facility data.
2. Washington County Power anticipates 300 hrs/yr of startup/shutdown activities on natural gas and 50 hrs/yr of startup/shutdown activities on fuel oil. Therefore, normal operation excludes startup/shutdown events. As each separate startup or shutdown requires less than 30 minutes of time, it is presumed that a shutdown and a startup event combined is the equivalent of 1 hour. Therefore, 300 startup/shutdown events is presumed to require 300 total hours of time per system.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) / 2,000 (lbs/ton)
4. Hourly emissions for the Normal Operation Period are based on the maximum hourly emission rate for turbine combustion of natural gas and fuel oil. Annual emissions for the Normal Operation Period are based on the sum of annual emission rates for turbine combustion of natural gas and fuel oil.
5. Annual emissions are the sum of emissions under normal operation period and startup/shutdown period.

Table B-17. Project Actual Criteria Pollutant Emissions from Combustion Turbine No. 1

Pollutant	Annual Emissions (tpy)
SO_2	2.30
NO_X	152.73
CO	70.86
Total PM	43.00
Filterable PM	27.15
Condensable PM	15.85
Total PM_{10}	43.00
Total $PM_{2.5}$	43.00
VOC	25.61
Sulfuric Acid Mist (H_2SO_4)	1.07
GHGs	387,496

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr
Turbine Operating Hours	3,000	hrs/yr

Table B-18. Projected Actual HAP Emissions from Turbine No. 1 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	4.30E-07	7.59E-04	1.14E-03
Acetaldehyde	4.00E-05	0.07	0.11
Acrolein	6.40E-06	0.01	0.02
Benzene	1.20E-05	0.02	0.03
Ethylbenzene	3.20E-05	0.06	0.08
Formaldehyde	7.10E-04	1.25	1.88
Naphthalene	1.30E-06	2.30E-03	3.44E-03
PAH	2.20E-06	3.89E-03	0.01
Propylene oxide	2.90E-05	0.05	0.08
Toluene	1.30E-04	0.23	0.34
Xylenes	6.40E-05	0.11	0.17

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-3 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr
Turbine Operating Hours	500	hrs/yr

Table B-19. Projected Actual HAP Emissions from Turbine No. 1 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	1.60E-05	0.03	0.01
Arsenic	1.10E-05	0.02	0.01
Benzene	5.50E-05	0.10	0.03
Beryllium	3.10E-07	5.86E-04	1.46E-04
Cadmium	4.80E-06	0.01	2.27E-03
Chromium	1.10E-05	0.02	0.01
Formaldehyde	2.80E-04	0.53	0.13
Lead	1.40E-05	0.03	0.01
Manganese	7.90E-04	1.49	0.37
Mercury	1.20E-06	2.27E-03	5.67E-04
Naphthalene	3.50E-05	0.07	0.02
Nickel	4.60E-06	0.01	2.17E-03
PAH	4.00E-05	0.08	0.02
Selenium	2.50E-05	0.05	0.01

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Tables 3.1-4 and 3.1-5 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-20. Projected Actual HAP Emissions from Combustion Turbine No. 1

Pollutant	Annual Emissions (tpy)
1,3-Butadiene	0.01
Acetaldehyde	0.11
Acrolein	0.02
Arsenic	0.01
Benzene	0.06
Beryllium	1.46E-04
Cadmium	2.27E-03
Chromium	0.01
Ethylbenzene	0.08
Formaldehyde	2.01
Lead	0.01
Manganese	0.37
Mercury	5.67E-04
Naphthalene	0.02
Nickel	2.17E-03
PAH	0.02
Propylene oxide	0.08
Selenium	0.01
Toluene	0.34
Xylenes	0.17

<u>Simple Cycle Unit Operating Parameters - Natural Gas Combustion</u>

Heat Input	1,766	MMBtu/hr	
Operating Hours	2,700	hrs/yr	NOx, CO, VOC
	3000	hrs/yr	Other Pollutants

Table B-21. Projected Actual Criteria Pollutant Emissions from Turbine No. 2 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	6.00E-04	1.06	1.59
NO_X	3.00E-02	52.89	71.41
CO	1.82E-02	32.20	43.47
Total PM	1.37E-02	24.19	36.29
Filterable PM	9.00E-03	15.89	23.84
Condensable PM	4.70E-03	8.30	12.45
Total PM_{10}	1.37E-02	24.19	36.29
Total $PM_{2.5}$	1.37E-02	24.19	36.29
VOC	6.37E-03	11.24	15.17
Sulfuric Acid Mist (H_2SO_4)	4.00E-04	0.71	1.06
<u>GHGs</u>			
CO_2	116.98	206,580	309,870
CH_4	2.20E-03	3.89	5.84
N_2O	2.20E-04	0.39	0.58
CO_2e	117.10	206,793	310,190

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr	
Turbine Operating Hours	450	hrs/yr	NOx, CO, VOC
	500	hrs/yr	Other Pollutants

Table B-22. Projected Actual Criteria Pollutant Emissions from Turbine No. 2 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	1.50E-03	2.84	0.71
NO_X	1.40E-01	264.12	59.43
CO	4.05E-02	76.57	17.23
Total PM	1.42E-02	26.84	6.71
Filterable PM	7.00E-03	13.23	3.31
Condensable PM	7.20E-03	13.61	3.40
Total PM_{10}	1.42E-02	26.838	6.71
Total $PM_{2.5}$	1.42E-02	26.84	6.71
VOC	1.59E-02	30.07	6.77
Sulfuric Acid Mist (H_2SO_4)	1.40E-05	0.03	0.01
GHGs			
CO_2	163.05	308,169	77,042
CH_4	0.007	12.50	3.13
N_2O	0.001	2.50	0.63
CO_2e	163.61	309,226	77,307

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2, Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Startup/Shutdown Operating Parameters

Heat Input Natural Gas SUSD Hour	1,478	MMBtu/hr
Hours of Natural Gas SUSD	300	hrs/yr
Heat Input Fuel Oil SUSD Hour	1,582	MMBtu/hr
Hours of Fuel Oil SUSD	50	hrs/yr

Table B-23. Projected Actual Emissions from Turbine No. 2 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/MMBtu)	Operation Hours/ Events[2]	Potential Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	264.12	130.83
CO	--	--	76.57	60.70
VOC	--	--	30.07	21.94
Startup/Shutdown Period Natural Gas				
NO_X	0.05	300 hrs natural gas	79.68	11.95
CO	0.03		48.51	7.28
VOC	0.01		16.93	2.54
Startup/Shutdown Period Fuel Oil				
NO_X	0.25	50 hrs fuel oil	397.94	9.95
CO	0.07		115.36	2.88
VOC	0.03		45.30	1.13
Annual Emissions[5]				
NO_X	--	--	--	152.73
CO	--	--	--	70.86
VOC	--	--	--	25.61

1. Startup/shutdown emission factors based on engineering analysis of available facility data.
2. Washington County Power anticipates 300 hrs/yr of startup/shutdown activities on natural gas and 50 hrs/yr of startup/shutdown activities on fuel oil. Therefore, normal operation excludes startup/shutdown events. As each separate startup or shutdown requires less than 30 minutes of time, it is presumed that a shutdown and a startup event combined is the equivalent of 1 hour. Therefore, 300 startup/shutdown events is presumed to require 300 total hours of time per system.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) / 2,000 (lbs/ton)
4. Hourly emissions for the Normal Operation Period are based on the maximum hourly emission rate for turbine combustion of natural gas and fuel oil. Annual emissions for the Normal Operation Period are based on the sum of annual emission rates for turbine combustion of natural gas and fuel oil.
5. Annual emissions are the sum of emissions under normal operation period and startup/shutdown period.

Table B-24. Project Actual Criteria Pollutant Emissions from Combustion Turbine No. 2

Pollutant	Annual Emissions (tpy)
SO_2	2.30
NO_X	152.73
CO	70.86
Total PM	43.00
Filterable PM	27.15
Condensable PM	15.85
Total PM_{10}	43.00
Total $PM_{2.5}$	43.00
VOC	25.61
Sulfuric Acid Mist (H_2SO_4)	1.07
GHGs	387,496

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr
Turbine Operating Hours	3,000	hrs/yr

Table B-25. Projected Actual HAP Emissions from Turbine No. 2 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	4.30E-07	7.59E-04	1.14E-03
Acetaldehyde	4.00E-05	0.07	0.11
Acrolein	6.40E-06	0.01	0.02
Benzene	1.20E-05	0.02	0.03
Ethylbenzene	3.20E-05	0.06	0.08
Formaldehyde	7.10E-04	1.25	1.88
Naphthalene	1.30E-06	2.30E-03	3.44E-03
PAH	2.20E-06	3.89E-03	0.01
Propylene oxide	2.90E-05	0.05	0.08
Toluene	1.30E-04	0.23	0.34
Xylenes	6.40E-05	0.11	0.17

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-3 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr
Turbine Operating Hours	500	hrs/yr

Table B-26. Projected Actual HAP Emissions from Turbine No. 2 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	1.60E-05	0.03	0.01
Arsenic	1.10E-05	0.02	0.01
Benzene	5.50E-05	0.10	0.03
Beryllium	3.10E-07	5.86E-04	1.46E-04
Cadmium	4.80E-06	0.01	2.27E-03
Chromium	1.10E-05	0.02	0.01
Formaldehyde	2.80E-04	0.53	0.13
Lead	1.40E-05	0.03	0.01
Manganese	7.90E-04	1.49	0.37
Mercury	1.20E-06	2.27E-03	5.67E-04
Naphthalene	3.50E-05	0.07	0.02
Nickel	4.60E-06	0.01	2.17E-03
PAH	4.00E-05	0.08	0.02
Selenium	2.50E-05	0.05	0.01

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Tables 3.1-4 and 3.1-5 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-27. Projected Actual HAP Emissions from Combustion Turbine No. 2

Pollutant	Annual Emissions (tpy)
1,3-Butadiene	0.01
Acetaldehyde	0.11
Acrolein	0.02
Arsenic	0.01
Benzene	0.06
Beryllium	1.46E-04
Cadmium	2.27E-03
Chromium	0.01
Ethylbenzene	0.08
Formaldehyde	2.01
Lead	0.01
Manganese	0.37
Mercury	5.67E-04
Naphthalene	0.02
Nickel	2.17E-03
PAH	0.02
Propylene oxide	0.08
Selenium	0.01
Toluene	0.34
Xylenes	0.17

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr	
Operating Hours	2,700	hrs/yr	NOx, CO, VOC
	3000	hrs/yr	Other Pollutants

Table B-28. Projected Actual Criteria Pollutant Emissions from Turbine No. 3 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	6.00E-04	1.06	1.59
NO_X	3.00E-02	52.89	71.41
CO	1.82E-02	32.20	43.47
Total PM	1.37E-02	24.19	36.29
Filterable PM	9.00E-03	15.89	23.84
Condensable PM	4.70E-03	8.30	12.45
Total PM_{10}	1.37E-02	24.19	36.29
Total $PM_{2.5}$	1.37E-02	24.19	36.29
VOC	6.37E-03	11.24	15.17
Sulfuric Acid Mist (H_2SO_4)	4.00E-04	0.71	1.06
GHGs			
CO_2	116.98	206,580	309,870
CH_4	2.20E-03	3.89	5.84
N_2O	2.20E-04	0.39	0.58
CO_2e	117.10	206,793	310,190

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr	
Turbine Operating Hours	450	hrs/yr	NOx, CO, VOC
	500	hrs/yr	Other Pollutants

Table B-29. Projected Actual Criteria Pollutant Emissions from Turbine No. 3 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	1.50E-03	2.84	0.71
NO_X	1.40E-01	264.12	59.43
CO	4.05E-02	76.57	17.23
Total PM	1.42E-02	26.84	6.71
Filterable PM	7.00E-03	13.23	3.31
Condensable PM	7.20E-03	13.61	3.40
Total PM_{10}	1.42E-02	26.838	6.71
Total $PM_{2.5}$	1.42E-02	26.84	6.71
VOC	1.59E-02	30.07	6.77
Sulfuric Acid Mist (H_2SO_4)	1.40E-05	0.03	0.01
GHGs			
CO_2	163.05	308,169	77,042
CH_4	0.007	12.50	3
N_2O	0.001	2.50	1
CO_2e	163.61	309,226	77,307

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Startup/Shutdown Operating Parameters

Heat Input Natural Gas SUSD Hour	1,478	MMBtu/hr
Hours of Natural Gas SUSD	300	hrs/yr
Heat Input Fuel Oil SUSD Hour	1,582	MMBtu/hr
Hours of Fuel Oil SUSD	50	hrs/yr

Table B-30. Projected Actual Emissions from Turbine No. 3 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/MMBtu)	Operation Hours/ Events[2]	Potential Emissions[3] (lb/hr)	Potential Emissions[3] (tpy)
Normal Operation Period[4]				
NO_X	--	--	264.12	130.83
CO	--	--	76.57	60.70
VOC	--	--	30.07	21.94
Startup/Shutdown Period Natural Gas				
NO_X	0.05	300 hrs natural gas	79.68	11.95
CO	0.03		48.51	7.28
VOC	0.01		16.93	2.54
Startup/Shutdown Period Fuel Oil				
NO_X	0.25	50 hrs fuel oil	397.94	9.95
CO	0.07		115.36	2.88
VOC	0.03		45.30	1.13
Annual Emissions[5]				
NO_X	--	--	--	152.73
CO	--	--	--	70.86
VOC	--	--	--	25.61

1. Startup/shutdown emission factors based on engineering analysis of available facility data.
2. Washington County Power anticipates 300 hrs/yr of startup/shutdown activities on natural gas and 50 hrs/yr of startup/shutdown activities on fuel oil. Therefore, normal operation excludes startup/shutdown events. As each separate startup or shutdown requires less than 30 minutes of time, it is presumed that a shutdown and a startup event combined is the equivalent of 1 hour. Therefore, 300 startup/shutdown events is presumed to require 300 total hours of time per system.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) / 2,000 (lbs/ton)
4. Hourly emissions for the Normal Operation Period are based on the maximum hourly emission rate for turbine combustion of natural gas and fuel oil. Annual emissions for the Normal Operation Period are based on the sum of annual emission rates for turbine combustion of natural gas and fuel oil.
5. Annual emissions are the sum of emissions under normal operation period and startup/shutdown period.

Table B-31. Project Actual Criteria Pollutant Emissions from Combustion Turbine No. 3

Pollutant	Annual Emissions (tpy)
SO_2	2.30
NO_X	152.73
CO	70.86
Total PM	43.00
Filterable PM	27.15
Condensable PM	15.85
Total PM_{10}	43.00
Total $PM_{2.5}$	43.00
VOC	25.61
Sulfuric Acid Mist (H_2SO_4)	1.07
GHGs	387,496

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr
Turbine Operating Hours	3,000	hrs/yr

Table B-32. Projected Actual HAP Emissions from Turbine No. 3 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	4.30E-07	7.59E-04	1.14E-03
Acetaldehyde	4.00E-05	0.07	0.11
Acrolein	6.40E-06	0.01	0.02
Benzene	1.20E-05	0.02	0.03
Ethylbenzene	3.20E-05	0.06	0.08
Formaldehyde	7.10E-04	1.25	1.88
Naphthalene	1.30E-06	2.30E-03	3.44E-03
PAH	2.20E-06	3.89E-03	0.01
Propylene oxide	2.90E-05	0.05	0.08
Toluene	1.30E-04	0.23	0.34
Xylenes	6.40E-05	0.11	0.17

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-3 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr
Turbine Operating Hours	500	hrs/yr

Table B-33. Projected Actual HAP Emissions from Turbine No. 3 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	1.60E-05	0.03	0.01
Arsenic	1.10E-05	0.02	0.01
Benzene	5.50E-05	0.10	0.03
Beryllium	3.10E-07	5.86E-04	1.46E-04
Cadmium	4.80E-06	0.01	2.27E-03
Chromium	1.10E-05	0.02	0.01
Formaldehyde	2.80E-04	0.53	0.13
Lead	1.40E-05	0.03	0.01
Manganese	7.90E-04	1.49	0.37
Mercury	1.20E-06	2.27E-03	5.67E-04
Naphthalene	3.50E-05	0.07	0.02
Nickel	4.60E-06	0.01	2.17E-03
PAH	4.00E-05	0.08	0.02
Selenium	2.50E-05	0.05	0.01

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Tables 3.1-4 and 3.1-5 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-34. Projected Actual HAP Emissions from Combustion Turbine No. 3

Pollutant	Annual Emissions (tpy)
1,3-Butadiene	0.01
Acetaldehyde	0.11
Acrolein	0.02
Arsenic	0.01
Benzene	0.06
Beryllium	1.46E-04
Cadmium	2.27E-03
Chromium	0.01
Ethylbenzene	0.08
Formaldehyde	2.01
Lead	0.01
Manganese	0.37
Mercury	5.67E-04
Naphthalene	0.02
Nickel	2.17E-03
PAH	0.02
Propylene oxide	0.08
Selenium	0.01
Toluene	0.34
Xylenes	0.17

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr	
Operating Hours	2,700	hrs/yr	NOx, CO, VOC
	3000	hrs/yr	Other Pollutants

Table B-35. Projected Actual Criteria Pollutant Emissions from Turbine No. 4 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	6.00E-04	1.06	1.59
NO_X	3.00E-02	52.89	71.41
CO	1.82E-02	32.20	43.47
Total PM	1.37E-02	24.19	36.29
Filterable PM	9.00E-03	15.89	23.84
Condensable PM	4.70E-03	8.30	12.45
Total PM_{10}	1.37E-02	24.19	36.29
Total $PM_{2.5}$	1.37E-02	24.19	36.29
VOC	6.37E-03	11.24	15.17
Sulfuric Acid Mist (H_2SO_4)	4.00E-04	0.71	1.06
GHGs			
CO_2	116.98	206,580	309,870
CH_4	2.20E-03	3.89	5.84
N_2O	2.20E-04	0.39	0.58
CO_2e	117.10	206,793	310,190

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr	
Turbine Operating Hours	450	hrs/yr	NOx, CO, VOC
	500	hrs/yr	Other Pollutants

Table B-36. Projected Actual Criteria Pollutant Emissions from Turbine No. 4 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	1.50E-03	2.84	0.71
NO_X	1.40E-01	264.12	59.43
CO	4.05E-02	76.57	17.23
Total PM	1.42E-02	26.84	6.71
Filterable PM	7.00E-03	13.23	3.31
Condensable PM	7.20E-03	13.61	3.40
Total PM_{10}	1.42E-02	26.838	6.71
Total $PM_{2.5}$	1.42E-02	26.84	6.71
VOC	1.59E-02	30.07	6.77
Sulfuric Acid Mist (H_2SO_4)	1.40E-05	0.03	0.01
GHGs			
CO_2	163.05	308,169	77,042
CH_4	0.007	12.50	3.13
N_2O	0.001	2.50	0.63
CO_2e	163.61	309,226	77,307

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

<u>Startup/Shutdown Operating Parameters</u>

Heat Input Natural Gas SUSD Hour	1,478	MMBtu/hr
Hours of Natural Gas SUSD	300	hrs/yr
Heat Input Fuel Oil SUSD Hour	1,582	MMBtu/hr
Hours of Fuel Oil SUSD	50	hrs/yr

Table B-37. Projected Actual Emissions from Turbine No. 4 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/MMBtu)	Operation Hours/ Events[2]	Potential Emissions[3] (lb/hr)	Potential Emissions[3] (tpy)
Normal Operation Period[4]				
NO_X	--	--	264.12	130.83
CO	--	--	76.57	60.70
VOC	--	--	30.07	21.94
Startup/Shutdown Period Natural Gas				
NO_X	0.05	300 hrs natural gas	79.68	11.95
CO	0.03		48.51	7.28
VOC	0.01		16.93	2.54
Startup/Shutdown Period Fuel Oil				
NO_X	0.25	50 hrs fuel oil	397.94	9.95
CO	0.07		115.36	2.88
VOC	0.03		45.30	1.13
Annual Emissions[5]				
NO_X	--	--	--	152.73
CO	--	--	--	70.86
VOC	--	--	--	25.61

1. Startup/shutdown emission factors based on engineering analysis of available facility data.
2. Washington County Power anticipates 300 hrs/yr of startup/shutdown activities on natural gas and 50 hrs/yr of startup/shutdown activities on fuel oil. Therefore, normal operation excludes startup/shutdown events. As each separate startup or shutdown requires less than 30 minutes of time, it is presumed that a shutdown and a startup event combined is the equivalent of 1 hour. Therefore, 300 startup/shutdown events is presumed to require 300 total hours of time per system.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/MMBtu) * Heat Input (MMBtu/hr) / 2,000 (lbs/ton)
4. Hourly emissions for the Normal Operation Period are based on the maximum hourly emission rate for turbine combustion of natural gas and fuel oil. Annual emissions for the Normal Operation Period are based on the sum of annual emission rates for turbine combustion of natural gas and fuel oil.
5. Annual emissions are the sum of emissions under normal operation period and startup/shutdown period.

Table B-38. Project Actual Criteria Pollutant Emissions from Combustion Turbine No. 4

Pollutant	Annual Emissions (tpy)
SO_2	2.30
NO_X	152.73
CO	70.86
Total PM	43.00
Filterable PM	27.15
Condensable PM	15.85
Total PM_{10}	43.00
Total $PM_{2.5}$	43.00
VOC	25.61
Sulfuric Acid Mist (H_2SO_4)	1.07
GHGs	387,496

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,766	MMBtu/hr
Turbine Operating Hours	3,000	hrs/yr

Table B-39. Projected Actual HAP Emissions from Turbine No. 4 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	4.30E-07	7.59E-04	1.14E-03
Acetaldehyde	4.00E-05	0.07	0.11
Acrolein	6.40E-06	0.01	0.02
Benzene	1.20E-05	0.02	0.03
Ethylbenzene	3.20E-05	0.06	0.08
Formaldehyde	7.10E-04	1.25	1.88
Naphthalene	1.30E-06	2.30E-03	3.44E-03
PAH	2.20E-06	3.89E-03	0.01
Propylene oxide	2.90E-05	0.05	0.08
Toluene	1.30E-04	0.23	0.34
Xylenes	6.40E-05	0.11	0.17

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-3 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,890	MMBtu/hr
Turbine Operating Hours	500	hrs/yr

Table B-40. Projected Actual HAP Emissions from Turbine No. 4 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Average Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
1,3-Butadiene	1.60E-05	0.03	0.01
Arsenic	1.10E-05	0.02	0.01
Benzene	5.50E-05	0.10	0.03
Beryllium	3.10E-07	5.86E-04	1.46E-04
Cadmium	4.80E-06	0.01	2.27E-03
Chromium	1.10E-05	0.02	0.01
Formaldehyde	2.80E-04	0.53	0.13
Lead	1.40E-05	0.03	0.01
Manganese	7.90E-04	1.49	0.37
Mercury	1.20E-06	2.27E-03	5.67E-04
Naphthalene	3.50E-05	0.07	0.02
Nickel	4.60E-06	0.01	2.17E-03
PAH	4.00E-05	0.08	0.02
Selenium	2.50E-05	0.05	0.01

1. Emission factors for natural gas are from AP-42 Ch. 3.1 Stationary Gas Turbines, Tables 3.1-4 and 3.1-5 (April 2000).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-41. Projected Actual HAP Emissions from Combustion Turbine No. 4

Pollutant	Annual Emissions (tpy)
1,3-Butadiene	0.01
Acetaldehyde	0.11
Acrolein	0.02
Arsenic	0.01
Benzene	0.06
Beryllium	1.46E-04
Cadmium	2.27E-03
Chromium	0.01
Ethylbenzene	0.08
Formaldehyde	2.01
Lead	0.01
Manganese	0.37
Mercury	5.67E-04
Naphthalene	0.02
Nickel	2.17E-03
PAH	0.02
Propylene oxide	0.08
Selenium	0.01
Toluene	0.34
Xylenes	0.17

Fuel Oil Storage Tank Operating Parameters

Storage Components	Ultra Low-Sulfur Diesel	
Max Daily Operating	24	hours/day
Annual Operating Hours	8,760	hours/year
Tank Type	VFRT	
Tank Capacity	2,500,000	gallons
Tank Annual Throughput	30,000,000	gallons/yr

Table B-42. Fuel Oil Storage Tank Emissions

Pollutant	TankESP Output Losses (lb)	Potential Annual Emissions (tpy)
VOC	1,329.23	0.66
Benzene	2.62	1.31E-03
Ethylbenzene	4.07	2.03E-03
Hexane	0.52	2.62E-04
Naphthalene	0.62	3.10E-04
Toluene	30.65	1.53E-02
Xylene	79.29	3.96E-02

Table B-43. Historical Operating Hours for Turbines and Natural Gas Preheaters[1]

Year	Combustion Turbine No. 1 (hr/yr)	Combustion Turbine No. 2 (hr/yr)	Combustion Turbine No. 3 (hr/yr)	Combustion Turbine No. 4 (hr/yr)	Heaters No. 1 (hr/yr)	Heaters No. 2 (hrs/yr)	Turbine Totals (hr/yr)	Heater Totals (hrs)
2015	530	258	255	456	502	657	1,499	1,159
2016	40	498	364	74	606	578	976	1,184
2017	60	415	346	59	440	428	880	868
2018	166	258	264	225	399	460	913	859
2019	399	427	411	422	752	754	1,659	1,507
Average:	**239**	**371**	**328**	**247**	**540**	**576**	**1,185**	**1,115**

1. Historical hours of operation for Turbines as previously reported.

Hours of Operation - Turbines

Proposed: (4 Turbines Total)	12,000	hours (3,000 hours of natural gas combustion proposed for each turbine)
Annual Average: (2015 - 2020)	1,185	hours
Ratio =	Proposed/Annual Average	
=	10.12	
Associated Increase = (2 Heaters Total)	**Proposed - Annual Average**	
=	**10,176**	**hours**
~	**5,088**	**hours per Heater**

Hours of Operation - Heaters

Annual Average: (2015 - 2020)	1,115	hours
Ratio:	10.12	
Proposed = (2 Heaters Total)	Heaters Annual Average * Ratio	
=	11,291	hours

<u>Fuel Heater Operating Parameters</u>

Fuel Type	Natural Gas	
Fuel Heating Value	1,020	Btu/scf
No. of Heaters	2	
Sulfur Content of Fuel (S)	0.50	gr/100 scf
Operating Hours Increase	5,088	hrs/yr
Nominal Heat Input	10.10	MMBtu/hr
Hourly Fuel Usage	0.0099	MMscf/hr

Table B-44. Associated Emissions Increases of Criteria Pollutants from Fuel Heaters (Nos.

Pollutant	Emission Factor[1] (lb/MMscf)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	1.43	0.03	0.07
NO_X	100.00	1.98	5.04
CO	84.00	1.66	4.23
Total PM	7.60	0.15	0.38
Condensable PM	5.70	0.11	0.29
Filterable PM	1.90	0.04	0.10
PM_{10}	7.60	0.15	0.38
$PM_{2.5}$	7.60	0.15	0.38
VOC	5.50	0.11	0.28
H_2SO_4	0.33	0.01	0.02
GHGs			
CO_2	119,317	2,363	6,011
CH_4	2.25	0.04	0.11
N_2O	0.22	4.45E-03	0.01
CO_2e	119,440	2,365	6,017

1. See Table B-6 for details on emission factors for external natural gas combustion.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMscf) * Fuel Usage (MMscf/hr) * No. of Heaters
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-45. Associated Emissions Increases of HAPs from Fuel Heaters (Nos. 1 and 2)

Pollutant	Emission Factor[1] (lb/MMscf)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
Arsenic	2.00E-04	3.96E-06	1.01E-05
Benzene	2.10E-03	4.16E-05	1.06E-04
Beryllium	1.20E-05	2.38E-07	6.05E-07
Cadmium	1.10E-03	2.18E-05	5.54E-05
Chromium	1.40E-03	2.77E-05	7.05E-05
Cobalt	8.40E-05	1.66E-06	4.23E-06
Dichlorobenzene	1.20E-03	2.38E-05	6.05E-05
Formaldehyde	7.50E-02	1.49E-03	3.78E-03
Hexane	1.80	0.04	0.09
Lead	5.00E-04	9.90E-06	2.52E-05
Manganese	3.80E-04	7.53E-06	1.91E-05
Mercury	2.60E-04	5.15E-06	1.31E-05
Naphthalene	6.10E-04	1.21E-05	3.07E-05
Nickel	2.10E-03	4.16E-05	1.06E-04
POM	6.98E-04	1.38E-05	3.52E-05
Selenium	2.40E-05	4.75E-07	1.21E-06
Toluene	3.40E-03	6.73E-05	1.71E-04

1. Emission factors obtained from AP-42 Ch. 1.4 Natural Gas Combustion, Tables 1.4-2, 1.4-3, and 1.4-4 (July 1998).
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMscf) * Fuel Usage (MMscf/hr) * No. of Heaters
3. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-46. Project Associated Units Emissions Increases

Pollutant	Emissions Increases from Heaters (tpy)	Associated Units Emissions Increases (tpy)
Filterable PM	0.10	0.10
Total PM_{10}	0.38	0.38
Total $PM_{2.5}$	0.38	0.38
SO_2	0.07	0.07
NO_X	5.04	5.04
VOC	0.28	0.28
CO	4.23	4.23
CO_2e	6,017	6,017.37
Lead	2.52E-05	2.52E-05
Sulfuric Acid Mist	1.65E-02	0.02

Table B-47. Project PSD Emissions Increase Evaluation

Pollutant	A Modified Unit Baseline Emissions (tpy)[1]	B Modified Unit Projected Actual Emissions (tpy)[1]	C New Unit Potential Emissions (tpy)[2]	D Emissions Increase from New & Modified Units (D = C + B - A) (tpy)[3]	E Associated Units Emissions Increases (tpy)	F Project Emissions Increases (F = D + E) (tpy)[4]	PSD Significant Emission Rate (tpy)	PSD Triggered? (Yes/No)
Filterable PM	11.58	108.59	--	97.02	0.10	97.11	25	Yes
Total PM_{10}	17.63	172.00	--	154.38	0.38	154.76	15	Yes
Total $PM_{2.5}$	17.63	172.00	--	154.38	0.38	154.76	10	Yes
SO_2	0.40	9.19	--	8.79	0.07	8.86	40	No
NO_X	50.00	610.94	--	560.94	5.04	565.97	40	Yes
VOC	8.19	102.45	0.66	94.93	0.28	95.21	40	Yes
CO	23.46	283.44	--	259.98	4.23	264.21	100	Yes
CO_2e	153,070	1,549,985	--	1,396,914	6,017	1,402,932	75,000	Yes
Lead	--	0.03	--	0.03	2.52E-05	0.03	0.60	No
Sulfuric Acid Mist	0.51	4.26	--	3.75	0.02	3.77	7.00	No

1. The four existing site turbines are the modified units with respect to this PSD assessment.
2. The fuel oil storage tank is a new unit with respect to this PSD assessment.
3. Emissions Increase from New and Modified Units (tpy) = New Unit Potential Emissions (tpy) + Modified Unit Projected Actual Emissions (tpy) - Modified Unit Baseline Emissions (tpy)
4. Project Emissions Increases (tpy) = Emissions Increase from New and Modified Units (tpy) + Associated Units Emissions Increases (tpy)

APPENDIX C. RBLC SEARCH RESULTS

RBLC SEARCH RESULTS – NO_X

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
PANDA SHERMAN POWER STATION	PANDA SHERMAN POWER LLC	GRAYSON	TX	2/3/2010	A combined-cycle power plant producing a nominal 600 MW with two Siemens SGT6-5000F (501F) or two GE 7FA gas turbines.	State permit 87225	Natural Gas-fired Turbines	16.210	Natural Gas	600	MW	2 Siemens SGT6-5000F or 2 GE Frame 7FA. Both capable of combined or simple cycle operation. 468 MMBtu/hr duct burners.	Nitrogen Oxides (NOx)	Dry low NOx combustors and Selective Catalytic Reduction	9.00	PPMVD	@ 15% O2, ROLLNG 24-HR AVG, SIMPLE CYCLE
DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY	SOUTHERN POWER COMPANY	JACKSON	GA	5/14/2010	PLANT DAHLBERG HAS PROPOSED TO CONSTRUCT AND OPERATE FOUR ADDITIONAL SIMPLE-CYCLE COMBUSTION TURBINES (SOURCE CODES: CT11-CT14) AND ONE FUEL OIL STORAGE TANK. THE PROPOSED PROJECT WILL HAVE A NOMINAL GENERATING CAPACITY OF 760 MW. THE FACILITY IS CURRENTLY PERMITTED TO OPERATE 10 DUAL-FUELED SIMPLE-CYCLE CTG's. AFTER THE EXPANSION, THE FACILITY WILL HAVE A TOTAL NOMINAL GENERATING CAPACITY OF 1530 MW.		SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	15.110	NATURAL GASE	1,530	MW	THE PROCESS USES FUEL OIL FOR BACKUP AT THE RATE OF 2129 MMBUT/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS (FIRING NATURAL GAS). WATER INJECTION (FIRING FUEL OIL).	9.00	PPM@15%02	3 HOUR AVERAGE/CONDITION 3.3.23
DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY	SOUTHERN POWER COMPANY	JACKSON	GA	5/14/2010	PLANT DAHLBERG HAS PROPOSED TO CONSTRUCT AND OPERATE FOUR ADDITIONAL SIMPLE-CYCLE COMBUSTION TURBINES (SOURCE CODES: CT11-CT14) AND ONE FUEL OIL STORAGE TANK. THE PROPOSED PROJECT WILL HAVE A NOMINAL GENERATING CAPACITY OF 760 MW. THE FACILITY IS CURRENTLY PERMITTED TO OPERATE 10 DUAL-FUELED SIMPLE-CYCLE CTG's. AFTER THE EXPANSION, THE FACILITY WILL HAVE A TOTAL NOMINAL GENERATING CAPACITY OF 1530 MW.		SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	15.110	NATURAL GASE	1,530	MW	THE PROCESS USES FUEL OIL FOR BACKUP AT THE RATE OF 2129 MMBUT/H	Nitrogen Oxides (NOx)	DRY LOW NOx BURNERS (FIRING NATURAL GAS), WATER INJECTION (FIRING FUEL OIL).	297.00	T/YR	12 CONSECUTIVE MONTH AVERAGE /CONDITION
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	natural gas	800	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Nitrogen Oxides (NOx)	Good combustor design, Water Injection and Selective Catalytic Reduction (SCR)	5.00	PPMVD AT 15% O2	1-HR AVE
HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	CUMBERLAND	NJ	9/16/2010			SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(25 MW)	15.110	NATURAL GAS	5,000	MMFT3/YR	THE PROCESS CONSISTS OF ONE NEW TRENT 60 SIMPLE CYCLE COMBUSTION TURBINE. THE TURBINE WILL GENERATE 64 MW OF ELECTRICITY USING NATURAL GAS AS A PRIMARY FUEL (UP TO 8760 HOURS PER YEAR), WITH A BACKUP FUEL OF ULTRA LOW SULFUR DIESEL FUEL (ULSD) WHICH CAN ONLY BE COMBUSTED FOR A MAXIMUM OF 500 HOURS PER YEAR AND ONLY DURING NATURAL GAS CURTAILMENT. THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING NATURAL GAS IS 590 MMBTU/HR AND THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING ULSD IS 568 MMBTU/HR. THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION TO CONTROL NOX EMISSION AND A CATALYTIC OXIDIZER TO CONTROL CO AND VOC EMISSION.	Nitrogen Oxides (NOx)	THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX EMISSION AND USE CLEAN FUELS NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL TO MINIMIZE NOX EMISSIONS	2.50	PPMVD@15% O2	3HR ROLLING AVERAGE BASED ON 1-HR BLOCK
CUNNINGHAM POWER PLANT	SOUTHWESTERN PUBLIC SERVICE CO.	LEA	NM	5/2/2011	Electric steam generating facility providing commercial electric power using natural gas fired boilers and turbines.	Simple Cycle Combustion Turbines. Permit revises the NOx BACT ppmvd limit for turbines established in permit PSD-NM-622-M2 issued 2-10-97 because turbines have not been able to meet NOx BACT limits. No modification or change to mass emissions. Former NOx BACT was at 15 ppmvd w/out power augmentation (normal mode) and 25 ppmvd w/ power augmentation (see RBLC ID NM-0028). Entry also clarifies the existing CO, SOx, and PM BACT.	Normal Mode (without Power Augmentation)	15.110	natural gas	-			Nitrogen Dioxide (NO2)	Dry Low NOx Burners Type K & Good Combustion Practice	21.00	PPMVD	HOUR
CUNNINGHAM POWER PLANT	SOUTHWESTERN PUBLIC SERVICE CO.	LEA	NM	5/2/2011	Electric steam generating facility providing commercial electric power using natural gas fired boilers and turbines.	Simple Cycle Combustion Turbines. Permit revises the NOx BACT ppmvd limit for turbines established in permit PSD-NM-622-M2 issued 2-10-97 because turbines have not been able to meet NOx BACT limits. No modification or change to mass emissions. Former NOx BACT was at 15 ppmvd w/out power augmentation (normal mode) and 25 ppmvd w/ power augmentation (see RBLC ID NM-0028). Entry also clarifies the existing CO, SOx, and PM BACT.	Power Augmentation	15.110	natural gas	-		Increase power output by lowering the outlet air temperatur through water inejctinos into the compressor.	Nitrogen Dioxide (NO2)	Dry Low NOx burners, Type K. Good Combustion Practices as defined in the permit.	30.00	PPMVD	HOURLY
CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	CALCASIEU	LA	12/21/2011	320 MW POWER PLANT COMPRISED OF 2 NATURAL GAS-FIRED SIMPLE CYCLE COMBUSTION TURBINES.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD TRIGGERED DUE TO RELAXATION OF A FEDERALLY-ENFORCEABLE CONDITION LIMITING POTENTIAL EMISSIONS BELOW MAJOR STATIONARY SOURCE THRESHOLDS.	TURBINE EXHAUST STACK NO. 1 & NO. 2	15.110	NATURAL GAS	1,900	MM BTU/H EACH		Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTORS	240.00	LB/H	HOURLY MAXIMUM
YORK GENERATION FACILITY	YORK PLANT HOLDINGS, LLC	YORK COUNTY	PA	3/1/2012	This plan approval will allow for the construction and temporary operation of two new combustion turbines at the facility.		COMBUSTION TURBINE, DUAL FUEL, T01 and T02 (2 Units)	15.900	Natural Gas	634	MMBTU/H	The combined number of hours of operation for both turbines shall not exceed 6000 hours per each consecutive 12-month period. The combined number of hours of distillate fuel oil firing for both turbines shall not exceed 1700 hours per each consecutive 12-month period. The liquid distillate fuel oil fired in the combustion turbines shall be ultra low sulfur kerosene - maximum sulfur content of 15 ppm or ultra low sulfur diesel (ULSD) - maximum sulfur content of 15 ppm (as defined in ASTM standard D975 Table 1). In addition to operational limits, air emissions will be minimized by Catalytic Oxidizer for CO control and Water injection followed by Selective Catalytic Reduction system utilizing aqueous ammonia for NOx control.	Nitrogen Oxides (NOx)	In addition to operational limitations, air emissions will be minimized by the following add-on control equipment: a. Water injection followed by Selective Catalytic Reduction System (SCR) utilizing aqueous ammonia for NOx control; b. Catalytic oxidizer for CO control	2.50	PPMVD	BASED ON 3-HOUR AVERAGE, ROLLING BY 1-HR

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
CEDAR BAYOU ELECTRIC GERNERATION STATION	NRG TEXAS POWER	CHAMBERS	TX	9/12/2012	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The units will produce between 215-263 MW each.		Simple Cycle Combustion Turbines	15.110	Natural Gas	225	MW	The gas turbines will be one of three options: (1) Two Siemens Model F5 (SF5) CTGs each rated at nominal capability of 225 megawatts (MW). (2) Two General Electric Model 7FA (GE7FA) CTGs each rated at nominal capability of 215 MW. (3) Two Mitsubishi Heavy Industry G Frame (MHI501G) CTGs each rated at a nominal electric output of 263 MW.	Nitrogen Oxides (NOx)	DLN	9.00	PPM	3HR. ROLLING AVG.
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONERS MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (NORMAL OPERATION)	15.110	NATURAL GAS	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Nitrogen Oxides (NOx)	WATER INJECTION, SCR	2.50	PPMVD	@15% O2, 1-HR AVG
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONERS MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (STARTUP & SHUTDOWN PERIODS)	15.110	NATURAL GAS	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Nitrogen Oxides (NOx)	water injection and SCR system	22.50	LB/H	STARTUP EVENTS
R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	MORTON	ND	2/22/2013	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.		Combustion Turbine	15.110	Natural gas	986	MMBTU/H	Turbine is a GE Model PG 7121 (7EA) used as a peaking unit.	Nitrogen Oxides (NOx)	Dry low-NOx combustion (DLN)	9.00	PPMVD @15% OYYGEN	4 H.R.A. WHEN > 50MWE AND > 0 DEGREES F
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405	MMBTU/hr		Nitrogen Oxides (NOx)	water injection	25.00	PPMDV	24-HR ROLLING AVE; CORRECTED TO 15% O
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405	MMBTU/hr		Nitrogen Dioxide (NO2)	dry low NOx burners and fire only pipeline natural gas	9.00	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE 7FA Simple Cycle Combustion Turbine	15.110	Pipeline quality natural gas	1,780	MMBTU/HR		Nitrogen Oxides (NOx)	dry low NOx burners and fire only pipeline natural gas	9.00	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	5/13/2013	The proposed project is for two natural gas fired simple cycle CTGs. The proposed models include GE7Fa.03 and GE7Fa.05. They have an output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each.		Simple Cycle Combustion Turbines	15.110	natural gas	180	MW		Nitrogen Oxides (NOx)	Dry low NOx combustor	9.00	PPMVD	15%O2, 3HR ROLLING BASIS
PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	WILLIAMS	ND	5/14/2013	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	The permit was for the addition of 2 turbines to the station. Since a synthetic minor limit was relaxed for the first unit, BACT was required for all three turbines.	Natural gas-fired turbines	15.110	Natural gas	451	MMBTU/H	Rating is for each turbine.	Nitrogen Oxides (NOx)	Water injection plus SCR	5.00	PPPMVD	4 HR. ROLLING AVERAGE EXCEPT FOR STARTUP
LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	MCKENZIE	ND	9/16/2013	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.		Natural Gas Fired Simple Cycle Turbines	15.110	Natural gas	412	MMBTU/H	The heat input is for a single unit.	Nitrogen Oxides (NOx)	SCR	5.00	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP
GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS LP	GUADALUPE	TX	10/4/2013	Installing two natural gas-fired simple-cycle peaking combustion turbine generators. The two CTGs will produce between 383 and 454 MW combined. Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5.		(2) simple cycle turbines	16.110	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5. 383 MW to 454 MW total plant capacity.	Nitrogen Oxides (NOx)	DLN burners, limited operation	9.00	PPMVD	@15% O2, 3 HOUR ROLLING AVG
RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MONTCALM	MI	11/1/2013	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Other facility-wide pollutants not listed below (tpy): PM10=211.19+ PM2.5=205.24+ Lead=0.0027+ CO2e=5,398,441+ Sulfuric Acid Mist=5.67+	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	15.210	Natural gas	2,147	MMBTU/H	FG-CTG1-4: Four natural gas fired CTGs with each turbine containing a heat recovery steam generator (HRSG) to operate in combined cycle. Two CTGs (with HRSGs) are connected to one steam turbine generator. Each CTG is equipped with a dry low NOx (DLN) burner, a selective catalytic reduction (SCR) system, and a catalytic oxidation system. The throughput capacity is 2,147 MMBtu/hr for each CTG. The turbines are existing simple cycle turbines that will be retrofit to be combined cycle units.	Nitrogen Oxides (NOx)	Dry Low NOx burners (DLN) and Selective Catalytic Reduction (SCR) system.	2.00	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN
RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MONTCALM	MI	11/1/2013	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Other facility-wide pollutants not listed below (tpy): PM10=211.19+ PM2.5=205.24+ Lead=0.0027+ CO2e=5,398,441+ Sulfuric Acid Mist=5.67+	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	15.210	Natural gas	2,807	MMBTU/H	Four natural gas-fired CTGs with each turbine containing a heat recovery steam generator (HRSG) to operate in combined cycle. The two CTGs (with HRSGs) are connected to one steam turbine generator. Each CTG is equipped with a dry low NOx (DLN) burner and a selective catalytic reduction (SCR) system, and a catalytic oxidation system. Additionally, the HRSG is operated with a natural gas fired duct burner during supplemental firing. The turbines are existing simple cycle turbines which will be retrofit to be combined cycle. Operational restriction is 4000 hrs/year that each DB can operate.	Nitrogen Oxides (NOx)	Dry low NOx burner (DLN) and selective catalytic reduction system (SCR).	2.00	PPMVOL	3-H ROLL AVG., EXCEPT STARTUP/SHUTDOWN

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MONTCALM	MI	11/1/2013	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Other facility-wide pollutants not listed below (tpy): PM10=211.19+ PM2.5=205.24+ Lead=0.0027+ CO2e=5,398,441+ Sulfuric Acid Mist=5.67+	FG-CTG1-4 Startup/Shutdown	15.210	Natural gas	2,147	MMBTU/H	Four natural gas-fired CTGs operating in startup/shutdown mode.	Nitrogen Oxides (NOx)	Dry low NOx burners (DLN) and selective catalytic reduction (SCR) system.	176.90	PPH	EACH CTG W/O DB; HR LIMIT DURING STARTUP
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1,690	MMBTU/H		Nitrogen Oxides (NOx)	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.50	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1,690	MMBTU/H		Nitrogen Oxides (NOx)	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.50	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	4/22/2014	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	In this project, 24 peaking turbines from the Lauderdale facility are being replaced with five 200 MW combustion turbines at Lauderdale. The turbines will fire primarily natural gas, but may also fire ULSD fuel oil. Triggers PSD for NOx, PM, CO, VOC, and GHG. GHG permit issued by US EPA Region 4. Technical evaluation available at http://arm-permit2k.dep.state.fl.us/nontv/0110037.011.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural gas	2,000	MMBtu/hr (approx)	Throughput could vary slightly (+/- 120 MMBtu/hr) depending on final selection of turbine model and firing of natural gas or oil. Primary fuel is expected to be gas. Each turbine limited to 3300 hrs per rolling 12-month period. Of these 3300 hrs, no more than 500 may use ULSD fuel oil.	Nitrogen Oxides (NOx)	Required to employ dry low-NOx technology and wet injection. Water injection must be used when firing ULSD.	9.00	PPMVD @ 15% O2	24-HR BLOCK AVG, BY CEMS (NAT GAS)
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	4/22/2014	GSEC is proposing to build three additional new CTGs at the existing Antelope Elk Energy Center. The new facility will provide primarily peaking and intermediate power needs. The new units will be GE 7F5-Series gas turbines in simple cycle application, rated at 202 MW. Each turbine will operate a maximum of 4,572 hours per year.		Combustion Turbine-Generator(CTG)	15.110	Natural Gas	202	MW	Simple Cycle	Nitrogen Oxides (NOx)	DLN	9.00	PPM	15% O2, 3 HR. ROLLING AVG.
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE INC	HALE	TX	4/22/2014	Golden Spread Electric Cooperative (GSEC) currently owns and operates Antelope Station (now renamed Antelope Elk Energy Center), a 168 MW generating facility made up of 18 quick start WÃ¤rtsilÃ¤ engines. GSEC is proposing to build a new combustion turbine-generator (CTG) facility at Antelope Station, while the 18 WÃ¤rtsilÃ¤ engines will remain and continue to be authorized by TCEQ Standard Permit. The new turbine-generator will provide primarily peaking and intermediate power needs in a highly cyclical operation. The CTG will produce approximately 100 - 200 MW of electricity, depending on loading and ambient temperature.		combustion turbine	15.110	natural gas	202	MW	new GE 7FA 5-Series gas turbine in a simple cycle application, with a maximum electric output of 202 megawatts (MW) and a maximum design capacity of 1,941 million British thermal units per hour (MMBtu/hr). The turbine will operate a maximum of 4,572 hours per year.	Nitrogen Oxides (NOx)	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	8/1/2014	The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County.		(2) combustion turbines	15.110	natural gas	180	MW	(2) GE 7FA.03, 2500 hours of operation per year each	Nitrogen Oxides (NOx)	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVG
ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	GRIMES	TX	9/22/2014	The proposed project is to construct and operate the RPGS comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the model of combustion turbine (CT) selected. The applicant is considering three models of CTs; one model will be selected and the permit revised to reflect the selection before construction begins. The three CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F.		(2) simple cycle turbines	15.110	natural gas	600	MW	The three possible CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F. will operate 2,920 hours per year at full load for each CT	Nitrogen Oxides (NOx)	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVG
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	12/11/2014	Electric generation	Permit modification to convert startup and shutdown BACT limits to an hourly basis (from event based).	Turbines - two simple cycle gas	15.110	natural gas	800	MMBTU/H each	GE LMS100PA, natural gas fired, simple cycle, combustion turbine.	Nitrogen Oxides (NOx)	SCR and dry low NOx burners	23.00	LB/H	1-HR AVE / STARTUP AND SHUTDOWN
SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	HARRIS	TX	12/19/2014	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The new units will produce between 215-263 MW each.		Simple cycle natural gas turbines	15.110	Natural Gas	225	MW		Nitrogen Oxides (NOx)	DLN	9.00	PPM	3HR ROLLING AVG.
INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	WHARTON	TX	2/2/2015	Indeck Wharton, L.L.C. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode.		(3) combustion turbines	15.110	natural gas	220	MW	The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode	Nitrogen Oxides (NOx)	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVERAGE

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	GUADALUPE	TX	5/8/2015	Navasota South Peakers Operating Company II LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Nitrogen Oxides (NOx)	dry low-NOx (DLN) burners	9.00	PPMVD @ 15% O2	3-HR AVERAGE
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine & Generator	15.110	natural gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Nitrogen Oxides (NOx)	Dry Low NOx burners	9.00	PPMVD AT 15% O2	
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed. Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators. Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1. Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	15.210	Natural gas	2,022	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Nitrogen Oxides (NOx)	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	14.70	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed. Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators. Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1. Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	15.210	Natural gas	2,144	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Nitrogen Oxides (NOx)	dry-low NOx (DLN) burner and selective catalytic reduction (SCR)	15.60	LB/H	WITHOUT DUCT BURNERS. SEE NOTES.
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural gas	2,100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Nitrogen Oxides (NOx)	Dry-low-NOx combustion system. Wet injection when firing ULSD.	9.00	PPMVD@15% O2	24-HR BLOCK AVERAGE
FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	LEE	FL	9/10/2015	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will be replaced with two new GE 7F.05 turbines, each with nominal capacity of 200 MW	Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0710002.022.AC.D.ZIP	Combustion Turbines	15.110	Natural Gas	2,262	MMBtu/hr gas	Two GE 7F.05 turbines, approximately 200 MW each. Natural-gas is primary fuel. Permitted 3390 hr/yr of operation, of which no more than 500 hr may be on fuel oil. Dry Low-NOx, with wet injection for oil firing.	Nitrogen Oxides (NOx)	DLN and wet injection (for ULSD operation)	9.00	PPMVD@15% O2	GAS FIRING, 24-HR BLOCK AVG
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	10/9/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	natural gas	230	MW	Siemens Model SGT6-5000 F5ee â€" 230 MW or Second turbine option: General Electric Model 7FA.05TP â€" 227 MW	Nitrogen Oxides (NOx)	Dry Low NOx burners	9.00	PPMVD @ 15% O2	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (>25 MW)	15.110	natural gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Nitrogen Oxides (NOx)	Dry Low NOx burners, good combustion practices, limited operations	9.00	PPMVD @ 15% O2	
VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	GRAYSON	TX	10/27/2015	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Nitrogen Oxides (NOx)	DLN burners	9.00	PPMVD @ 15% O2	3-HR AVERAGE
UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	NIXON	TX	12/9/2015	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Nitrogen Oxides (NOx)	dry low NOX burners	9.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE PEAK

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines > 25 MW	15.110	natural gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Nitrogen Oxides (NOx)	Dry low-NOx burners (DLN), good combustion practices	9.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	2.00	PPM	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	natural gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Nitrogen Oxides (NOx)	Emission controls consist of dry low-NOx combustors (DLN). DLN combustors use two stages of combustion, transitioning from initial startup with fuel and flame in the primary nozzles only, through a lean lean stage with fuel and flame in the primary and secondary nozzles, to fuel in the secondary stage only, extinguishing the primary flame, and in full operation, premix mode, with fuel to both nozzles, but flame only in the second stage. When natural gas and air are well-mixed before combustion, the flame temperature and resulting NOx emissions are greatly reduced compared to conventional diffusion flame combustion.	9.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	natural gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Nitrogen Oxides (NOx)	Emission controls consist of dry low-NOx combustors (DLN). DLN combustors use two stages of combustion, transitioning from initial startup with fuel and flame in the primary nozzles only, through a lean lean stage with fuel and flame in the primary and secondary nozzles, to fuel in the secondary stage only, extinguishing the primary flame, and in full operation, premix mode, with fuel to both nozzles, but flame only in the second stage. When natural gas and air are well-mixed before combustion, the flame temperature and resulting NOx emissions are greatly reduced compared to conventional diffusion flame combustion.	9.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE
BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2,143,980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel	2.50	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
INVENERGY NELSON EXPANSION LLC	INVENERGY	LEE	IL	9/27/2016	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.		Two Simple Cycle Combustion Turbines	15.110	Natural Gas	190	MW	Two simple cycle combustion turbines used for peaking purposes and fired primarily on natural gas with ULSD as a secondary fuel.	Nitrogen Oxides (NOx)	Dry low-NOx combustion technology for natural gas and low-NOx combustion technology and water injection for ULSD.	0.03	LB/MMBTU	

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1,961	MMBTU/HR		Nitrogen Oxides (NOx)	Low NOx Burners/Combustion Technology	9.00	PPM	VD/12 MO ROLLING TOTAL
PUENTE POWER		VENTURA	CA	10/13/2016	Utility		Gas turbine	15.110	Natural gas	262	MW		Nitrogen Oxides (NOx)		2.50	PPMVD	1 HOUR@15%O2
WAVERLY FACILITY	PLEASANTS ENERGY, LLC	PLEASANTS	WV	1/23/2017	300 MW, natural gas fired, simple cycle peaking power facility	In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included. Please contact above engineer for more information. There are two identical turbines but only one is listed.	GE Model 7FA Turbine	15.110	Natural Gas	1,571	mmbtu/hr	There are two identical units at the facility.	Nitrogen Oxides (NOx)	Dry Low-NOx Combustion System (DLNB), Water Injection	9.00	PPM	NATURAL GAS
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	a facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	natural gas	1,069	mm btu/hr		Nitrogen Oxides (NOx)	good combustion practices and dry low nox burners	15.00	PPMVD	@15%O2
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	natural gas	228	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Nitrogen Oxides (NOx)	Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention)	9.00	PPMV	15% O2 3-H AVG
MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	YOAKUM	TX	8/16/2017	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.		Simple Cycle Turbine	15.110	NATURAL GAS	163	MW	Unit 6 Turbine is limited to 3000 hours per year.	Nitrogen Oxides (NOx)	Dry low-NOx burners	9.00	PPMVD	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	natural gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Nitrogen Oxides (NOx)	Dry low NOx burners	9.00	PPMVD	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	-			Nitrogen Oxides (NOx)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR	
WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	PLEASANTS	WV	3/13/2018	300 MW Single-Cycle Peaking Plant	Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add ‘‘advanced gas path‘‘ technology to the turbines that was defined as a ‘‘change in the method of operation‘‘ that resulted a major modification to the turbines.	GE 7FA.004 Turbine	15.110	Natural Gas	168	MW	This one entry is for both turbines as they are the same. Each turbine, after this modification, is a nominal 167.8 MW GE Model 7FA.004. Has oil-fire backup.	Nitrogen Oxides (NOx)	Dry LNB	69.00	LB/HR	
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	15.110	Natural Gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	240.00	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	15.110	natural gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	240.00	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2,201	MM BTU/hR	Limited to 600 hr/yr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	86.38	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2,201	MM BTU/hr	limited to 600 hr/yr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	86.38	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	9.00	PPMVD @15%O2	30-DAY ROLLING AVERAGE
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hours per year	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	9.00	PPMVD @15%O2	30-DAY ROLLING AVERAGE
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	natural gas	540	mm btu/hr		Nitrogen Oxides (NOx)	DLN and SCR	5.00	PPMVD	@ 15% O2
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Nitrogen Oxides (NOx)	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.	9.00	PPMV	30 DAY ROLLING AVERAGE

Table C-1. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	NATL GAS	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Nitrogen Oxides (NOx)	Dry Low NOx burners. Good combustion practices	9.00	PPMVD	15% O2
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control.	3.00	PPM	PPMVD@15%O2; 24-H AVG; SEE NOTES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Nitrogen Oxides (NOx)	Dry low NOx burners (DLNB) and good combustion practices.	25.00	PPM	AT 15%O2;4-HR ROLL AVG; SEE NOTES BELOW
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control.	3.00	PPM	PPMVD@15%O2; 24-H ROLL AVG; SEE NOTES
SABINE PASS LNG TERMINAL	SABINE PASS LNG LP AND SABINE PASS LIQUEFACTION LL	CAMERON	LA	9/6/2019	a terminal to import lng and liquefy/export natural gas Modification to add startup, shutdown, maintenance scenarios		gas turbines during startups, shutdowns, and maintenance	15.110	natural gas	-		during startups, shutdowns, and maintenance	Nitrogen Oxides (NOx)	good combustion practices	96.00	PPMV	@ 15% O2
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskaâ€™s Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Nitrogen Oxides (NOx)	DLN combustors and Good Combustion Practices	15.00	PPMV @ 15% O2	3-HOUR AVERAGE
ECTOR COUNTY ENERGY CENTER	ECTOR COUNTY ENERGY CENTER LLC	ECTOR	TX	8/17/2020	increase the hours of operation for the two simple cycle gas turbines		Simple Cycle Turbines	15.110	natural gas	-			Nitrogen Oxides (NOx)	Equipped with dry-low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS by 140 lb/hr maximum allowable emission rate for each turbine.	9.00	PPMVD	3% O2 3 HR AVG

Table C-2. RBLC Search Results for Large Fuel Oil Fired Turbines (Simple-Cycle) - NO_X

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	PRESQUE ISLE	MI	6/29/2011	Coal-fired power plant.		Turbine generator (EUBLACKSTART)	15.190	Diesel	540	MMBTU/H	This is a turbine generator identified in the permit as EUBLACKSTART. It has a throughput capacity of 540MMBTU/HR which equates to 102 MW. The maximum operation was based on 500 hours per year.	Nitrogen Oxides (NOx)		0.16	LB/MMBTU	TEST PROTOCOL
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water iniection.	Nitrogen Oxides (NOx)	DLN, WATER INJECTION	42.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE

RBLC SEARCH RESULTS – PM

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SOUTHERN POWER COMPANY	JACKSON	GA	5/14/2010	PLANT DAHLBERG HAS PROPOSED TO CONSTRUCT AND OPERATE FOUR ADDITIONAL SIMPLE-CYCLE COMBUSTION TURBINES (SOURCE CODES: CT11-CT14) AND ONE FUEL OIL STORAGE TANK. THE PROPOSED PROJECT WILL HAVE A NOMINAL GENERATING CAPACITY OF 760 MW. THE FACILITY IS CURRENTLY PERMITTED TO OPERATE 10 DUAL-FUELED SIMPLE-CYCLE CTG's. AFTER THE EXPANSION, THE FACILITY WILL HAVE A TOTAL NOMINAL GENERATING CAPACITY OF 1530 MW.		SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	15.110	Natural Gas	1530	MW	THE PROCESS USES FUEL OIL FOR BACKUP AT THE RATE OF 2129 MMBUT/H	Particulate matter, total PM10 (TPM10)	GOOD COMBUSTION PRACTICES PIPELINE QUALITY NATURAL GAS, ULTRA LOW SULFUR DISTILLATE FUEL	9.1	LB/H	3 HOUR AVERAGE/CONDITION 3.3.23
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	Natural Gas	799.7	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Particulate matter, total (TPM)	Use of pipeline quality natural gas and good combustor design	6.6	LB/H	AVE OVER STACK TEST LENGTH
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	Natural Gas	799.7	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Particulate matter, total PM10 (TPM10)	Use of pipeline quality natural gas and good combustor design	6.6	LB/H	AVE OVER STACK TEST LENGTH
HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	CUMBERLAND	NJ	9/16/2010			SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(25 MW)	15.110	Natural Gas	5000	MMFT3/YR	THE PROCESS CONSISTS OF ONE NEW TRENT 60 SIMPLE CYCLE COMBUSTION TURBINE. THE TURBINE WILL GENERATE 64 MW OF ELECTRICITY USING NATURAL GAS AS A PRIMARY FUEL (UP TO 8760 HOURS PER YEAR), WITH A BACKUP FUEL OF ULTRA LOW SULFUR DIESEL FUEL (ULSD) WHICH CAN ONLY BE COMBUSTED FOR A MAXIMUM OF 500 HOURS PER YEAR AND ONLY DURING NATURAL GAS CURTAILMENT. THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING NATURAL GAS IS 590 MMBTU/HR AND THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING ULSD IS 568 MMBTU/HR. THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION TO CONTROL NOX EMISSION AND A CATALYTIC OXIDIZER TO CONTROL CO AND VOC EMISSION.	Particulate matter, filterable PM10 (FPM10)	USE OF CLEAN BURNING FUELS; NATURAL GAS AS PRIMARY FUEL AND ULTRA LOW SULFUR DISTILLATE OIL WITH 15 PPMSULFUR BY WEIGHT AS BACKUP FUEL	5	LB/H	AVERAGE OF THREE TESTS
HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	CUMBERLAND	NJ	9/16/2010			SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(25 MW)	15.110	Natural Gas	5000	MMFT3/YR	THE PROCESS CONSISTS OF ONE NEW TRENT 60 SIMPLE CYCLE COMBUSTION TURBINE. THE TURBINE WILL GENERATE 64 MW OF ELECTRICITY USING NATURAL GAS AS A PRIMARY FUEL (UP TO 8760 HOURS PER YEAR), WITH A BACKUP FUEL OF ULTRA LOW SULFUR DIESEL FUEL (ULSD) WHICH CAN ONLY BE COMBUSTED FOR A MAXIMUM OF 500 HOURS PER YEAR AND ONLY DURING NATURAL GAS CURTAILMENT. THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING NATURAL GAS IS 590 MMBTU/HR AND THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING ULSD IS 568 MMBTU/HR. THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION TO CONTROL NOX EMISSION AND A CATALYTIC OXIDIZER TO CONTROL CO AND VOC EMISSION.	Particulate matter, filterable PM2.5 (FPM2.5)	USE OF CLEAN BURNING FUELS; NATURAL GAS AS PRIMARY FUEL AND ULTRA LOW SULFUR DISTILLATE OIL WITH 15 PPMSULFUR BY WEIGHT AS BACKUP FUEL	5	LB/H	AVERAGE OF THREE TESTS
PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	HUDSON	NJ	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION IS AN EXISTING ELECTRICITY GENERATING STATION.	This project consists of six new identical General Electric LM6000 sprint simple cycle combustion turbines burning natural gas. Each turbine will have a heat input rate of 485 million British thermal units per hour (MMBtu/hr) based on the high heating value of fuel (HHV). The combined maximum electricity generated by the six turbines will be 294 MW based on 2,978 hours of operation per turbine per year. All six new turbines will have water injection along with Selective Catalytic Reduction (SCR) systems to reduce Nitrogen Oxide (NOx) emissions and an oxidation catalyst to reduce Carbon Monoxide (CO) emissions	SIMPLE CYCLE TURBINE	15.110	Natural Gas	8940000	MMBtu/year (HHV)	Throughput <= 8.94xE6 MMBtu/year (HHV) combined for all six gas turbines. The 6 turbines are identical LM6000 simple cycle combustion turbines.	Particulate matter, total PM10 (TPM10)	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H	AVERAGE OF THREE TESTS

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	HUDSON	NJ	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION IS AN EXISTING ELECTRICITY GENERATING STATION.	This project consists of six new identical General Electric LM6000 sprint simple cycle combustion turbines burning natural gas. Each turbine will have a heat input rate of 485 million British thermal units per hour (MMBtu/hr) based on the high heating value of fuel (HHV). The combined maximum electricity generated by the six turbines will be 294 MW based on 2,978 hours of operation per turbine per year. All six new turbines will have water injection along with Selective Catalytic Reduction (SCR) systems to reduce Nitrogen Oxide (NOx) emissions and an oxidation catalyst to reduce Carbon Monoxide (CO) emissions	SIMPLE CYCLE TURBINE	15.110	Natural Gas	8940000	MMBtu/year (HHV)	Throughput <= 8.94xE6 MMBtu/year (HHV) combined for all six gas turbines. The 6 turbines are identical LM6000 simple cycle combustion turbines.	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H	AVERAGE OF THREE TESTS
PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	HUDSON	NJ	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION IS AN EXISTING ELECTRICITY GENERATING STATION.	This project consists of six new identical General Electric LM6000 sprint simple cycle combustion turbines burning natural gas. Each turbine will have a heat input rate of 485 million British thermal units per hour (MMBtu/hr) based on the high heating value of fuel (HHV). The combined maximum electricity generated by the six turbines will be 294 MW based on 2,978 hours of operation per turbine per year. All six new turbines will have water injection along with Selective Catalytic Reduction (SCR) systems to reduce Nitrogen Oxide (NOx) emissions and an oxidation catalyst to reduce Carbon Monoxide (CO) emissions	SIMPLE CYCLE TURBINE	15.110	Natural Gas	8940000	MMBtu/year (HHV)	Throughput <= 8.94xE6 MMBtu/year (HHV) combined for all six gas turbines. The 6 turbines are identical LM6000 simple cycle combustion turbines.	Particulate matter, filterable (FPM)	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H	AVERAGE OF THREE TESTS
CUNNINGHAM POWER PLANT	SOUTHWESTERN PUBLIC SERVICE CO.	LEA	NM	5/2/2011	Electric steam generating facility providing commercial electric power using natural gas fired boilers and turbines.	Simple Cycle Combustion Turbines. Permit revises the NOx BACT ppmvd limit for turbines established in permit PSD-NM-622-M2 issued 2-10-97 because turbines have not been able to meet NOx BACT limits. No modification or change to mass emissions. Former NOx BACT was at 15 ppmvd w/out power augmentation (normal mode) and 25 ppmvd w/ power augmentation (see RBLC ID NM-0028). Entry also clarifies the existing CO, SOx, and PM BACT.	Normal Mode (without Power Augmentation)	15.110	natural gas	0			Particulate matter, filterable PM10(FPM10)	Good combustion practices as defined in the permit.	5.4	LB/H	HOURLY
CUNNINGHAM POWER PLANT	SOUTHWESTERN PUBLIC SERVICE CO.	LEA	NM	5/2/2011	Electric steam generating facility providing commercial electric power using natural gas fired boilers and turbines.	Simple Cycle Combustion Turbines. Permit revises the NOx BACT ppmvd limit for turbines established in permit PSD-NM-622-M2 issued 2-10-97 because turbines have not been able to meet NOx BACT limits. No modification or change to mass emissions. Former NOx BACT was at 15 ppmvd w/out power augmentation (normal mode) and 25 ppmvd w/ power augmentation (see RBLC ID NM-0028). Entry also clarifies the existing CO, SOx, and PM BACT.	Power Augmentation	15.110	natural gas	0		Increase power output by lowering the outlet air temperatur through water inejctinos into the compressor.	Particulate matter, filterable PM10(FPM10)	Good combustion practices as defined in the permit.	5.4	LB/H	HOURLY
CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	CALCASIEU	LA	12/21/2011	320 MW POWER PLANT COMPRISED OF 2 NATURAL GAS-FIRED SIMPLE CYCLE COMBUSTION TURBINES.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD TRIGGERED DUE TO RELAXATION OF A FEDERALLY-ENFORCEABLE CONDITION LIMITING POTENTIAL EMISSIONS BELOW MAJOR STATIONARY SOURCE THRESHOLDS.	TURBINE EXHAUST STACK NO. 1 NO. 2	15.110	Natural Gas	1900	MM BTU/H EACH		Particulate matter, total PM2.5 (TPM2.5)	USE OF PIPELINE NATURAL GAS	17	LB/H	HOURLY MAXIMUM
CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	CALCASIEU	LA	12/21/2011	320 MW POWER PLANT COMPRISED OF 2 NATURAL GAS-FIRED SIMPLE CYCLE COMBUSTION TURBINES.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD TRIGGERED DUE TO RELAXATION OF A FEDERALLY-ENFORCEABLE CONDITION LIMITING POTENTIAL EMISSIONS BELOW MAJOR STATIONARY SOURCE THRESHOLDS.	TURBINE EXHAUST STACK NO. 1 NO. 2	15.110	Natural Gas	1900	MM BTU/H EACH		Particulate matter, total PM10 (TPM10)	USE OF PIPELINE NATURAL GAS	17	LB/H	HOURLY MAXIMUM
CEDAR BAYOU ELECTRIC GERNERATION STATION	NRG TEXAS POWER	CHAMBERS	TX	9/12/2012	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The units will produce between 215-263 MW each.		Simple Cycle Combustion Turbines	15.110	Natural Gas	225	MW	The gas turbines will be one of three options: (1) Two Siemens Model F5 (SF5) CTGs each rated at nominal capability of 225 megawatts (MW). (2) Two General Electric Model 7FA (GE7FA) CTGs each rated at nominal capability of 215 MW. (3) Two Mitsubishi Heavy Industry G Frame (MHI501G) CTGs each rated at a nominal electric output of 263 MW.	Particulate matter, filterable PM2.5 (FPM2.5)	Good Combustion Practices, Natural Gas	0		

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONER MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (NORMAL OPERATION)	15.110	Natural Gas	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Particulate matter, total (TPM)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONERSâ€™ MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (NORMAL OPERATION)	15.110	Natural Gas	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Particulate matter, total PM10 (TPM10)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONER MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (NORMAL OPERATION)	15.110	Natural Gas	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Particulate matter, filterable PM2.5 (FPM2.5)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER
R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	MORTON	ND	2/22/2013	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.		Combustion Turbine	15.110	Natural Gas	986	MMBTU/H	Turbine is a GE Model PG 7121 (7EA) used as a peaking unit.	Particulate matter, total PM10 (TPM10)	Good combustion practices.	7.3	LB/H	AVERAGE OF THREE TEST RUNS
R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	MORTON	ND	2/22/2013	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.		Combustion Turbine	15.110	Natural gas	986	MMBTU/H	Turbine is a GE Model PG 7121 (7EA) used as a peaking unit.	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices.	7.3	LB/H	AVERAGE OF THREE TEST RUNS
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405.3	MMBTU/hr		Particulate matter, total PM10 (TPM10)	fire only pipeline quality natural gas	6	LB/HR	AT FULL OAD
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405.3	MMBTU/hr		Particulate matter, total (TPM)	fire only pipeline quality natural gas	6	LB/HR	AT FULL LOAD
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE 7FA Simple Cycle Combustion Turbine	15.110	Pipeline quality natural gas	1780	MMBTU/HR		Particulate matter, total PM10 (TPM10)	will fire only pipeline quality natural gas	18	LB/HR	
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE 7FA Simple Cycle Combustion Turbine	15.110	Pipeline quality natural gas	1780	MMBTU/HR		Particulate matter, total (TPM)	will fire only pipeline quality natural gas	18	LB/HR	
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	5/13/2013	The proposed project is for two natural gas fired simple cycle CTGs. The proposed models include GE7Fa.03 and GE7Fa.05. They have an output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each.		Simple Cycle Combustion Turbines	15.110	Natural Gas	180	MW		Particulate matter, total PM2.5 (TPM2.5)	Firing pipeline quality natural gas and good combustion practices	0		
PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	WILLIAMS	ND	5/14/2013	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	The permit was for the addition of 2 turbines to the station. Since a synthetic minor limit was relaxed for the first unit, BACT was required for all three turbines.	Natural gas-fired turbines	15.110	Natural gas	451	MMBTU/H	Rating is for each turbine.	Particulate matter, total PM2.5 (TPM2.5)		5.4	LB/H	
ANCHORAGE MUNICIPAL LIGHT & POWER	MUNICIPALITY OF ANCHORAGE	MATANUSKA	AK	6/6/2013	Electric Utility	Authorized two natural gas turbines each rated at 408 MMBtu/hr, one ULSD Caterpillar generator rated at 2,000 ekW, and one cooling tower rated at 30,400 gallons per minute	Combustion	16.110	Natural Gas	408	MMBTU/H	Natural Gas-fired combustion turbine rated at 408.2 MMBtu/hr	Particulate matter, total PM2.5 (TPM2.5)	Good operation and combustion practices	0.0066	LB/MMBTU	

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	MCKENZIE	ND	9/16/2013	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.		Natural Gas Fired Simple Cycle Turbines	15.110	Natural gas	412	MMBTU/H	The heat input is for a single unit.	Particulate matter, total PM2.5 (TPM2.5)		5	LB/H	AVERAGE OF THREE TEST RUNS
GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS LP	GUADALUPE	TX	10/4/2013	Installing two natural gas-fired simple-cycle peaking combustion turbine generators. The two CTGs will produce between 383 and 454 MW combined. Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5.		(2) simple cycle turbines	16.110	Natural Gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5. 383 MW to 454 MW total plant capacity.	Particulate matter, total PM2.5 (TPM2.5)	natural gas fuel	0		
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	Natural Gas	1690	MMBTU/H		Particulate matter, total PM10 (TPM10)	Utilize only natural gas or ULSD fuel; Limit the time in startup or shutdown.	9.1	LB/H TOTAL PM	6-HR AVERAGE ON NG
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	4/22/2014	GSEC is proposing to build three additional new CTGs at the existing Antelope Elk Energy Center. The new facility will provide primarily peaking and intermediate power needs. The new units will be GE 7F5-Series gas turbines in simple cycle application, rated at 202 MW. Each turbine will operate a maximum of 4,572 hours per year.		Combustion Turbine-Generator(CTG)	15.110	Natural Gas	202	MW	Simple Cycle	Particulate matter, filterable PM2.5 (FPM2.5)	Pipeline quality natural gas; limited hours; Good combustion practices	0		
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE INC	HALE	TX	4/22/2014	Golden Spread Electric Cooperative (GSEC) currently owns and operates Antelope Station (now renamed Antelope Elk Energy Center), a 168 MW generating facility made up of 18 quick start engines. GSEC is proposing to build a new combustion turbine-generator (CTG) facility at Antelope Station, while the 18 engines will remain and continue to be authorized by TCEQ Standard Permit. The new turbine-generator will provide primarily peaking and intermediate power needs in a highly cyclical operation. The CTG will produce approximately 100 - 200 MW of electricity, depending on loading and ambient temperature.		combustion turbine	15.110	Natural Gas	202	MW	new GE 7FA 5-Series gas turbine in a simple cycle application, with a maximum electric output of 202 megawatts (MW) and a maximum design capacity of 1,941 million British thermal units per hour (MMBtu/hr). The turbine will operate a maximum of 4,572 hours per year.	Particulate matter, total PM2.5 (TPM2.5)		0		
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	5/30/2014	Power generation facility		Turbine - simple cycle gas	15.110	Natural Gas	375	MMBTU/H	One (1) General Electric, simple cycle, gas turbine electric generator, Unit 6 (CT08), model: LM6000, SN: N/A, rated at 375 MMBtu per hour.	Particulate matter, total PM10 (TPM10)	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	4.8	LB/H	3-HR AVE
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	5/30/2014	Power generation facility		Turbine - simple cycle gas	15.110	Natural Gas	375	MMBTU/H	One (1) General Electric, simple cycle, gas turbine electric generator, Unit 6 (CT08), model: LM6000, SN: N/A, rated at 375 MMBtu per hour.	Particulate matter, total PM2.5 (TPM2.5)	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	4.8	LB/H	3-HR AVE
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	8/1/2014	The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County.		(2) combustion turbines	15.110	Natural Gas	180	MW	(2) GE 7FA.03, 2500 hours of operation per year each	Particulate matter, total PM2.5 (TPM2.5)		0		
ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	GRIMES	TX	9/22/2014	The proposed project is to construct and operate the RPGS comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the model of combustion turbine (CT) selected. The applicant is considering three models of CTs; one model will be selected and the permit revised to reflect the selection before construction begins. The three CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F.		(2) simple cycle turbines	15.110	Natural Gas	600	MW	The three possible CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F. will operate 2,920 hours per year at full load for each CT	Particulate matter, total PM2.5 (TPM2.5)		0		

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	HARRIS	TX	12/19/2014	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The new units will produce between 215-263 MW each.		Simple cycle natural gas turbines	15.110	Natural Gas	225	MW		Particulate matter, filterable PM2.5 (FPM2.5)	Good Combustion Practices, natural gas	0		
INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	WHARTON	TX	2/2/2015	Indeck Wharton, L.L.C. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode.		(3) combustion turbines	15.110	Natural Gas	220	MW	The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode	Particulate matter, total PM2.5 (TPM2.5)		0		
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine Generator	15.110	Natural Gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices.	0		
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine Generator	15.110	Natural Gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices.	0		
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine Generator	15.110	Natural Gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices.	0		
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural Gas	2100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Particulate matter, total (TPM)	Clean fuel prevents PM formation	2	GR. S / 100 SCF GAS	FUEL RECORD KEEPING
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural Gas	2100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Particulate matter, total PM10 (TPM10)	Clean fuel prevents PM formation	2	GR. S / 100 SCF	FUEL RECORD KEEPING
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural Gas	2100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Particulate matter, total PM2.5 (TPM2.5)	Clean fuel prevents PM formation	2	GR. S / 100 SCF	FUEL RECORD KEEPING
FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	LEE	FL	9/10/2015	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will be replaced with two new GE 7F.05 turbines, each with nominal capacity of 200 MW	Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0710002.022.AC.D.ZIP	Combustion Turbines	15.110	Natural Gas	2262.4	MMBtu/hr gas	Two GE 7F.05 turbines, approximately 200 MW each. Natural-gas is primary fuel. Permitted 3390 hr/yr of operation, of which no more than 500 hr may be on fuel oil. Dry Low-NOx, with wet injection for oil firing.	Particulate matter, total (TPM)	Use of clean fuels, and annual VE test	2	GR S / 100 SCF GAS	FOR NATURAL GAS

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	LEE	FL	9/10/2015	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will be replaced with two new GE 7F.05 turbines, each with nominal capacity of 200 MW	Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0710002.022.AC.D.ZIP	Combustion Turbines	15.110	Natural Gas	2262.4	MMBtu/hr gas	Two GE 7F.05 turbines, approximately 200 MW each. Natural-gas is primary fuel. Permitted 3390 hr/yr of operation, of which no more than 500 hr may be on fuel oil. Dry Low-NOx, with wet injection for oil firing.	Particulate matter, total PM10 (TPM10)	Use of clean fuels	2	GR S / 100 SCF GAS	FOR NATURAL GAS
FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	LEE	FL	9/10/2015	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will be replaced with two new GE 7F.05 turbines, each with nominal capacity of 200 MW	Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0710002.022.AC.D.ZIP	Combustion Turbines	15.110	Natural gas	2262.4	MMBtu/hr gas	Two GE 7F.05 turbines, approximately 200 MW each. Natural-gas is primary fuel. Permitted 3390 hr/yr of operation, of which no more than 500 hr may be on fuel oil. Dry Low-NOx, with wet injection for oil firing.	Particulate matter, total PM2.5 (TPM2.5)	Use of clean fuels	2	GR S / 100 SCF GAS	FOR NATURAL GAS
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	10/9/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	Natural Gas	230	MW	Siemens Model SGT6-5000 F5ee 230 MW or Second turbine option: General Electric Model 7FA.05TP 227 MW	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices.	84.1	LB/HR	
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	10/9/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	Natural Gas	230	MW	Siemens Model SGT6-5000 F5ee 230 MW Second turbine option: General Electric Model 7FA.05TP 227 MW	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices.	84.1	LB/HR	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (25 MW)	15.110	Natural Gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (25 MW)	15.110	Natural Gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (25 MW)	15.110	Natural Gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR	
VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	GRAYSON	TX	10/27/2015	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	Natural Gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Particulate matter, total PM10 (TPM10)	Pipeline Quality Natural Gas	8.6	LB/H	
VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	GRAYSON	TX	10/27/2015	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	Natural Gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Particulate matter, total PM2.5 (TPM2.5)	Pipeline Quality Natural Gas	8.6	LB/H	
UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	NIXON	TX	12/9/2015	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle		Simple Cycle Turbine	15.110	Natural Gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Particulate matter, total PM10 (TPM10)	pipeline quality natural gas, good combustion practices	8.6	LB/H	
UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	NIXON	TX	12/9/2015	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle		Simple Cycle Turbine	15.110	Natural Gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Particulate matter, total PM2.5 (TPM2.5)	pipeline quality natural gas, good combustion practices	8.6	LB/H	

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	35.47	LB/H	
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	35.47	LB/H	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES, LOW SULFUR FUEL	19.35	LB/H	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	19.35	LB/H	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines 25 MW	15.110	Natural Gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Particulate matter, total PM10 (TPM10)	good combustion practices, low sulfur fuel	13.4	LB/H	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines 25 MW	15.110	Natural Gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Particulate matter, total PM2.5 (TPM2.5)	good combustion practices, low sulfur fuel	13.4	LB/H	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	Natural Gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Particulate matter, total PM10 (TPM10)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	14	LB/H	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	Natural Gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Particulate matter, total PM2.5 (TPM2.5)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	14	LB/H	
BAYONNE ENERGY CENTER	BAYONNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2143980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Particulate matter, filterable (FPM)	Use of Natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2143980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Particulate matter, total PM10 (TPM10)	Use of Natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR
BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2143980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Particulate matter, total PM2.5 (TPM2.5)	Use of natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR
INVENERGY NELSON EXPANSION LLC	INVENERGY	LEE	IL	9/27/2016	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.		Two Simple Cycle Combustion Turbines	15.110	Natural Gas	190	MW	Two simple cycle combustion turbines used for peaking purposes and fired primarily on natural gas with ULSD as a secondary fuel.	Particulate matter, filterable (FPM)	turbine design and good combustion practices	0.0038	LB/MMBTU	3-HOUR BLOCK AVERAGE
INVENERGY NELSON EXPANSION LLC	INVENERGY	LEE	IL	9/27/2016	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.		Two Simple Cycle Combustion Turbines	15.110	Natural Gas	190	MW	Two simple cycle combustion turbines used for peaking purposes and fired primarily on natural gas with ULSD as a secondary fuel.	Particulate matter, total PM10 (TPM10)	turbine design and good combustion practices	0.005	LB/MMBTU	3-HOUR BLOCK AVERAGE
INVENERGY NELSON EXPANSION LLC	INVENERGY	LEE	IL	9/27/2016	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.		Two Simple Cycle Combustion Turbines	15.110	Natural Gas	190	MW	Two simple cycle combustion turbines used for peaking purposes and fired primarily on natural gas with ULSD as a secondary fuel.	Particulate matter, total PM2.5 (TPM2.5)	turbine design and good combustion practices	0.005	LB/MMBTU	3-HOUR BLOCK AVERAGE
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1961	MMBTU/HR		Particulate matter, filterable (FPM)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	10	LB	H/12 MO ROLLING TOTAL

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1961	MMBTU/HR		Particulate matter, filterable PM10 (FPM10)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	12	LB	H/12 MO ROLLING TOTAL
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1961	MMBTU/HR		Particulate matter, total PM2.5 (TPM2.5)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	12	LB	H/12 MO ROLLING TOTAL
WAVERLY FACILITY	PLEASANTS ENERGY, LLC	PLEASANTS	WV	1/23/2017	300 MW, natural gas fired, simple cycle peaking power facility	In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included. Please contact above engineer for more information. There are two identical turbines but only one is listed.	GE Model 7FA Turbine	15.110	Natural Gas	1571	mmbtu/hr	There are two identical units at the facility.	Particulate matter, total PM2.5 (TPM2.5)	Inlet Air Filtration, Use of Natural Gas, Ultra-Low Sulfur Diesel	15	LB/HR	NATURAL GAS
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	A facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	Natural Gas	1069	mm btu/hr		Particulate matter, total PM10 (TPM10)	good combustion practices and fueled by natural gas	0.0076	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	A facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	Natural Gas	1069	mm btu/hr		Particulate matter, total PM2.5 (TPM2.5)	good combustion practices and fueled by natural gas	0.0076	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	Natural Gas	227.5	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR	
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	Natural Gas	227.5	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR	
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	Natural Gas	227.5	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR	

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	YOAKUM	TX	8/16/2017	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.		Simple Cycle Turbine	15.110	Natural Gas	162.8	MW	Unit 6 Turbine is limited to 3000 hours per year.	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas and good combustion practices	27	T/YR	
MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	YOAKUM	TX	8/16/2017	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.		Simple Cycle Turbine	15.110	Natural Gas	162.8	MW	Unit 6 Turbine is limited to 3000 hours per year.	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas and good combustion practices	27	T/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	Natural Gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Particulate matter, filterable (FPM)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	Natural Gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Particulate matter, total PM10 (TPM10)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	Natural Gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Particulate matter, total PM2.5 (TPM2.5)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	0			Particulate matter, total (TPM)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	0			Particulate matter, total PM10 (TPM10)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	0			Particulate matter, total PM2.5 (TPM2.5)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR	
WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	PLEASANTS	WV	3/13/2018	300 MW Sinple-Cycle Peaking Plant	Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add ‘‘advanced gas path‘‘ technology to the turbines that was defined as a ‘‘change in the method of operation‘‘ that resulted a major modification to the turbines.	GE 7FA.004 Turbine	15.110	Natural Gas	167.8	MW	This one entry is for both turbines as they are the same. Each turbine, after this modification, is a nominal 167.8 MW GE Model 7FA.004. Has oil-fire backup.	Particulate matter, total PM2.5 (TPM2.5)	Inlet air filtration.	15.09	LB/HR	
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	15.110	Natural Gas	2201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	15.110	Natural Gas	2201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	15.110	Natural Gas	2201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	15.110	Natural Gas	2201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2201	MM BTU/hR	Limited to 600 hr/yr	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2201	MM BTU/hR	Limited to 600 hr/yr	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2201	MM BTU/hr	limited to 600 hr/yr	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2201	MM BTU/hr	limited to 600 hr/yr	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hours per year	Particulate matter, total PM10 (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hours per year	Particulate matter, total PM2.5 (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	Natural Gas	540	mm btu/hr		Particulate matter, total PM10 (TPM10)	Good Combustion Practices and Use of low sulfur facility fuel gas	0.0066	LB/MM BTU	

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	Natural Gas	540	mm btu/hr		Particulate matter, total PM2.5 (TPM2.5)	Good Combustion Practices and Use of low sulfur facility fuel gas	0.0066	LB/MM BTU	
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Particulate matter, total PM10 (TPM10)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Particulate matter, total PM2.5 (TPM2.5)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	Natural Gas	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Particulate matter, filterable PM10 (FPM10)	Good combustion practices and use of pipeline quality natural gas.	7	LB/HR	
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	Natural Gas	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Particulate matter, filterable PM2.5 (FPM2.5)	Good combustion practices and use of pipeline quality natural gas.	7	LB/HR	
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas, inlet air conditioning, and good combustion practices.	6.02	LB/H	HOURLY
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas, inlet air conditioning, and good combustion practices.	6.02	LB/H	HOURLY
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas, inlet air conditioning, and good combustion practices.	6.02	LB/H	HOURLY

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	6.02	LB/H	HOURLY
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	15.110	Natural Gas	667	MMBTU/H	A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total PM2.5 (TPM2.5)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	15.110	Natural Gas	667	MMBTU/H	A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total PM10 (TPM10)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskas North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskas Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Particulate matter, total (TPM)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskas North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskas Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Particulate matter, total PM10 (TPM10)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE

Table C-3. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskas North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskas Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Particulate matter, total PM2.5 (TPM2.5)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE

Table C-4. RBLC Search Results for Large Fuel Oil Fired Turbines (Simple-Cycle) - PM

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	PRESQUE ISLE	MI	6/29/2011	Coal-fired power plant.		Turbine generator (EUBLACKSTART)	15.190	Diesel	540	MMBTU/H		Particulate matter, total PM10 (TPM10)		0.03	LB/MMBTU	TEST PROTOCOL
WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	PRESQUE ISLE	MI	6/29/2011	Coal-fired power plant.		Turbine generator (EUBLACKSTART)	15.190	Diesel	540	MMBTU/H	This is a turbine generator identified in the permit as EUBLACKSTART. It has a throughput capacity of 540MMBTU/HR which equates to 102 MW. The maximum operation was based on 500 hours per year.	Particulate matter, total PM2.5 (TPM2.5)		16.2	LB/H	TEST PROTOCOL
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water injection.	Particulate matter, total PM10 (TPM10)	combustor designed for complete combustion and therefore minimizes emissions	9.8	LB/H	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water injection.	Particulate matter, total PM2.5 (TPM2.5)	combustor designed for complete combustion and therefore minimizes emissions	9.8	LB/H	3-HR ROLLING AVERAGE

RBLC SEARCH RESULTS – CO

Table C-5. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - CO

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
PANDA SHERMAN POWER STATION	PANDA SHERMAN POWER LLC	GRAYSON	TX	2/3/2010	A combined-cycle power plant producing a nominal 600 MW with two Siemens SGT6-5000F (501F) or two GE 7FA gas turbines.	State permit 87225	Natural Gas-fired Turbines	16.210	Natural Gas	600	MW	2 Siemens SGT6-5000F or 2 GE Frame 7FA. Both capable of combined or simple cycle operation. 468 MMBtu/hr duct burners.	Carbon Monoxide	Good combustion practices	4.00	PPMVD	@ 15% O2, ROLLNG 24-HR AVG, SIMPLE CYCLE
DAHLBERG COMBUSTION TURBINE ELECTRIC GENERATING FACILITY	SOUTHERN POWER COMPANY	JACKSON	GA	5/14/2010	PLANT DAHLBERG HAS PROPOSED TO CONSTRUCT AND OPERATE FOUR ADDITIONAL SIMPLE-CYCLE COMBUSTION TURBINES (SOURCE CODES: CT11-CT14) AND ONE FUEL OIL STORAGE TANK. THE PROPOSED PROJECT WILL HAVE A NOMINAL GENERATING CAPACITY OF 760 MW. THE FACILITY IS CURRENTLY PERMITTED TO OPERATE 10 DUAL-FUELED SIMPLE-CYCLE CTG's. AFTER THE EXPANSION, THE FACILITY WILL HAVE A TOTAL NOMINAL GENERATING CAPACITY OF 1530 MW.		SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	15.110	NATURAL GASE	1,530	MW	THE PROCESS USES FUEL OIL FOR BACKUP AT THE RATE OF 2129 MMBUT/H	Carbon Monoxide	GOOD COMBUSTION PRACTICES	9.00	PPM@15%02	3-HOUR AVERAGE/CONDITION 3.3.24
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	natural gas	800	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Carbon Monoxide	Good Combustion Control and Catalytic Oxidation (CatOx)	10.00	PPMVD AT 15% O2	1-HR AVE
HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	CUMBERLAND	NJ	9/16/2010			SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(>25 MW)	15.110	NATURAL GAS	5,000	MMFT3/YR	THE PROCESS CONSISTS OF ONE NEW TRENT 60 SIMPLE CYCLE COMBUSTION TURBINE. THE TURBINE WILL GENERATE 64 MW OF ELECTRICITY USING NATURAL GAS AS A PRIMARY FUEL (UP TO 8760 HOURS PER YEAR), WITH A BACKUP FUEL OF ULTRA LOW SULFUR DIESEL FUEL (ULSD) WHICH CAN ONLY BE COMBUSTED FOR A MAXIMUM OF 500 HOURS PER YEAR AND ONLY DURING NATURAL GAS CURTAILMENT. THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING NATURAL GAS IS 590 MMBTU/HR AND THE MAXIMUM HEAT INPUT RATE WHILE COMBUSTING ULSD IS 568 MMBTU/HR. THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION TO CONTROL NOX EMISSION AND A CATALYTIC OXIDIZER TO CONTROL CO AND VOC EMISSION.	Carbon Monoxide	THE TURBINE WILL UTILIZE A CATALYTIC OXIDIZER TO CONTROL CO EMISSION, IN ADDITION TO USING CLEAN BURNING FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH 15 PPM SULFUR BY WEIGHT	5.00	PPMVD@15% O2	3HR ROLLING AVERAGE BASED ON 1-HR BLOCK
PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	HUDSON	NJ	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION IS AN EXISTING ELECTRICITY GENERATING STATION.	This project consists of six new identical General Electric LM6000 sprint simple cycle combustion turbines burning natural gas. Each turbine will have a heat input rate of 485 million British thermal units per hour (MMBtu/hr) based on the high heating value of fuel (HHV). The combined maximum electricity generated by the six turbines will be 294 MW based on 2,978 hours of operation per turbine per year. All six new turbines will have water injection along with Selective Catalytic Reduction (SCR) systems to reduce Nitrogen Oxide (NOx) emissions and an oxidation catalyst to reduce Carbon Monoxide (CO) emissions	SIMPLE CYCLE TURBINE	15.110	Natural Gas	8,940,000	MMBtu/year (HHV)	Throughput <= 8.94xE6 MMBtu/year (HHV) combined for all six gas turbines. The 6 turbines are identical LM6000 simple cycle combustion turbines.	Carbon Monoxide	Oxidation Catalyst, Good combustion practices	5.00	PPMVD@15% O2	3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK
CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	CALCASIEU	LA	12/21/2011	320 MW POWER PLANT COMPRISED OF 2 NATURAL GAS-FIRED SIMPLE CYCLE COMBUSTION TURBINES.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD TRIGGERED DUE TO RELAXATION OF A FEDERALLY-ENFORCEABLE CONDITION LIMITING POTENTIAL EMISSIONS BELOW MAJOR STATIONARY SOURCE THRESHOLDS.	TURBINE EXHAUST STACK NO. 1; NO. 2	15.110	NATURAL GAS	1,900	MM BTU/H EACH		Carbon Monoxide	DRY LOW NOX COMBUSTORS	781.00	LB/H	HOURLY MAXIMUM
CEDAR BAYOU ELECTRIC GERNERATION STATION	NRG TEXAS POWER	CHAMBERS	TX	9/12/2012	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The units will produce between 215-263 MW each.		Simple Cycle Combustion Turbines	15.110	Natural Gas	225	MW	The gas turbines will be one of three options: (1) Two Siemens Model F5 (SF5) CTGs each rated at nominal capability of 225 megawatts (MW). (2) Two General Electric Model 7FA (GE7FA) CTGs each rated at nominal capability of 215 MW. (3) Two Mitsubishi Heavy Industry G Frame (MHI501G) CTGs each rated at a nominal electric output of 263 MW.	Carbon Monoxide	Good Combustion Practices	9.00	PPM	1HR ROLLING AVG.
R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	MORTON	ND	2/22/2013	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.		Combustion Turbine	15.110	Natural gas	986	MMBTU/H	Turbine is a GE Model PG 7121 (7EA) used as a peaking unit.	Carbon Monoxide	Good Combustion	25.00	PPMVD @ 15% OXYGEN	4 H.R.A./WHEN > 50 MWE
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405	MMBTU/hr		Carbon Monoxide	utilize efficient combustion/design technology	63.80	LB/HR	FULL LOAD, AMBIENT TEMP < OR = TO 54 F
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE 7FA Simple Cycle Combustion Turbine	15.110	Pipeline quality natural gas	1,780	MMBTU/HR		Carbon Monoxide	utilize efficient combustion/design technology	39.00	LB/HR	AT FULL LOAD
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	5/13/2013	The proposed project is for two natural gas fired simple cycle CTGs. The proposed models include GE7Fa.03 and GE7Fa.05. They have an output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each.		Simple Cycle Combustion Turbines	15.110	natural gas	180	MW		Carbon Monoxide	Good combustion practices	9.00	PPMVD	15%O2, 3HR AVERAGE
PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	WILLIAMS	ND	5/14/2013	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	The permit was for the addition of 2 turbines to the station. Since a synthetic minor limit was relaxed for the first unit, BACT was required for all three turbines.	Natural gas-fired turbines	15.110	Natural gas	451	MMBTU/H	Rating is for each turbine.	Carbon Monoxide	Catalytic oxidation system	6.00	PPMVD	8 HR. ROLLING AVERAGE/EXCEPT STARTUP
LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	MCKENZIE	ND	9/16/2013	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.		Natural Gas Fired Simple Cycle Turbines	15.110	Natural gas	412	MMBTU/H	The heat input is for a single unit.	Carbon Monoxide	Oxidation Catalyst	6.00	PPMVD	8-HOUR ROLLING AVERAGE EXCEPT STARTUP

Table C-5. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - CO

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS LP	GUADALUPE	TX	10/4/2013	Installing two natural gas-fired simple-cycle peaking combustion turbine generators. The two CTGs will produce between 383 and 454 MW combined. Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5.		(2) Simple cycle turbines	16.110	natural gas	190	MW	Four models are approved: GE7FA.03, GE7FA.04, GE7FA.05, or Siemens SW 5000F5. 383 MW to 454 MW total plant capacity.	Carbon Monoxide	DLN burners, limited operation	9.00	PPMVD	@15% O2, ALL LOADS
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1,690	MMBTU/H		Carbon Monoxide	Oxidation catalyst; Limit the time in startup or shutdown.	6.00	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	4/22/2014	GSEC is proposing to build three additional new CTGs at the existing Antelope Elk Energy Center. The new facility will provide primarily peaking and intermediate power needs. The new units will be GE 7F5-Series gas turbines in simple cycle application, rated at 202 MW. Each turbine will operate a maximum of 4,572 hours per year.		Combustion Turbine-Generator(CTG)	15.110	Natural Gas	202	MW	Simple Cycle	Carbon Monoxide	Good combustion practices; limited hours	9.00	PPMVD	15% O2, 3HR AVG.
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE INC	HALE	TX	4/22/2014	Golden Spread Electric Cooperative (GSEC) currently owns and operates Antelope Station (now renamed Antelope Elk Energy Center), a 168 MW generating facility made up of 18 quick start engines. GSEC is proposing to build a new combustion turbine-generator (CTG) facility at Antelope Station, while the 18 engines will remain and continue to be authorized by TCEQ Standard Permit. The new turbine-generator will provide primarily peaking and intermediate power needs in a highly cyclical operation. The CTG will produce approximately 100 - 200 MW of electricity, depending on loading and ambient temperature.		Combustion turbine	15.110	natural gas	202	MW	new GE 7FA 5-Series gas turbine in a simple cycle application, with a maximum electric output of 202 megawatts (MW) and a maximum design capacity of 1,941 million British thermal units per hour (MMBtu/hr). The turbine will operate a maximum of 4,572 hours per year.	Carbon Monoxide	DLN combustors, good combustion practices	9.00	PPMVD	@15% O2. 3-HR ROLLING AVERAGE
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	8/1/2014	The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County.		(2) combustion turbines	15.110	natural gas	180	MW	(2) GE 7FA.03, 2500 hours of operation per year each	Carbon Monoxide	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVG
ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	GRIMES	TX	9/22/2014	The proposed project is to construct and operate the RPGS comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the model of combustion turbine (CT) selected. The applicant is considering three models of CTs; one model will be selected and the permit revised to reflect the selection before construction begins. The three CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F.		(2) simple cycle turbines	15.110	natural gas	600	MW	The three possible CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F. will operate 2,920 hours per year at full load for each CT	Carbon Monoxide	DLN combustors	9.00	PPMVD	@15% O2, 3-HR ROLLING AVERAGE
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	12/11/2014	Electric generation	Permit modification to convert startup and shutdown BACT limits to an hourly basis (from event based).	Turbines - two simple cycle gas	15.110	natural gas	800	MMBTU/H each	GE LMS100PA, natural gas fired, simple cycle, combustion turbine.	Carbon Monoxide	Catalytic Oxidation.	55.00	LB/H	1-HR AVE / STARTUP AND SHUTDOWN
SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	HARRIS	TX	12/19/2014	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy Industry G Frame. The new units will produce between 215-263 MW each.		Simple cycle natural gas turbines	15.110	Natural Gas	225	MW		Carbon Monoxide	Good Combustion Practices	9.00	PPM	1HR ROLLING AVG.
INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	WHARTON	TX	2/2/2015	Indeck Wharton, L.L.C. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode.		(3) combustion turbines	15.110	natural gas	220	MW	The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode	Carbon Monoxide	DLN combustors	4.00	PPMVD	@15% O2, 3-HR ROLLING AVG - SIEMENS
CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	GUADALUPE	TX	5/8/2015	Navasota South Peakers Operating Company II LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturers output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Monoxide	DLN burners and good combustion practices	9.00	PPMVD @ 15% O2	ALL LOADS
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine; Generator	15.110	natural gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Carbon Monoxide	Good combustion practices; limited operating hours	9.00	PPMVD @ 15% O2	3-HR AVERAGE
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural gas	2,100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Carbon Monoxide	Good combustion minimizes CO formation	4.00	PPMVD@15% O2	NAT GAS, THREE 1-HR RUNS
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	10/9/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	natural gas	230	MW	Siemens Model SGT6-5000 F5ee â€“ 230 MW or Second turbine option: General Electric Model 7FA.05TP â€“ 227 MW	Carbon Monoxide	dry low NOx burners and lmiited operation, clean fuel	9.00	PPMVD @ 15% O2	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (> 25 MW)	15.110	natural gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Carbon Monoxide	dry low NOx burners, good combustion practices, limited operation	9.00	PPMVD @ 15% O2	

Table C-5. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - CO

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	GRAYSON	TX	10/27/2015	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturers output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Monoxide	DLN burners and good combustion practices	9.00	PPMVD @ 15% O2	
UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	NIXON	TX	12/9/2015	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturers output at baseload, ISO at 183 MW), operating as peaking units in simple cycle		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Monoxide	dry low NOx burners and good combustion practices	9.00	PPMVD @ 15% O2	ALL LOADS
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle; Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Carbon Monoxide	OXIDATION CATALYST	4.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines; 25 MW	15.110	natural gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Carbon Monoxide	good combustion practices	9.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle; Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Carbon Monoxide	OXIDATION CATALYST	4.00	PPM	HOURLY
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	natural gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Carbon Monoxide	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	9.00	PPMVD @ 15% O2	3-HR AVERAGE
BAYONNNE ENERGY CENTER	BAYONNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2,143,980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Carbon Monoxide	Add-on control is CO Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	5.00	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1,961	MMBTU/HR		Carbon Monoxide	Pipeline Quality Natural Gas	13.99	LB	H/12 MO ROLLING TOTAL
WAVERLY FACILITY	PLEASANTS ENERGY, LLC	PLEASANTS	WV	1/23/2017	300 MW, natural gas fired, simple cycle peaking power facility	In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included. Please contact above engineer for more information. There are two identical turbines but only one is listed.	GE Model 7FA Turbine	15.110	Natural Gas	1,571	mmbtu/hr	There are two identical units at the facility.	Carbon Monoxide	Good Combustion Practices	9.00	PPM	NATURAL GAS
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	a facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	natural gas	1,069	mmbtu/hr		Carbon Monoxide	good combustion practices and fueled by natural gas	15.00	PPMVD	@15%O2
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	0	TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	natural gas	228	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Carbon Monoxide	Good combustion practices; limited operating hours	9.00	PPMVD	3% O2 3-H AVG

Table C-5. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - CO

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	natural gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Carbon Monoxide	Dry low NOx burners	9.00	PPMVD	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	-			Carbon Monoxide	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR	
WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	PLEASANTS	WV	3/13/2018	300 MW Simple-Cycle Peaking Plant	Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.	GE 7FA.004 Turbine	15.110	Natural Gas	168	MW	This one entry is for both turbines as they are the same. Each turbine, after this modification, is a nominal 167.8 MW GE Model 7FA.004. Has oil-fire backup.	Carbon Monoxide	Combustion Controls	33.90	LB/HR	
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	15.110	Natural Gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	2,000.00	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	15.110	natural gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	2,000.00	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2,201	MM BTU/hR	Limited to 600 hr/yr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	800.08	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2,201	MM BTU/hr	limited to 600 hr/yr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	800.08	LB/HR	HOURLY MAXIMUM
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	6.00	PPMVD AT 15% OXYGEN	ANNUAL AVERAGE
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hours per year	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	6.00	PPMVD AT 15% O2	ANNUAL AVERAGE
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	natural gas	540	mm btu/hr		Carbon Monoxide	Good Combustion Practices	25.00	PPMVD	@ 15% O2
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	25.00	PPMV	30 DAY ROLLING AVERAGE
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	NATL GAS	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Carbon Monoxide	Dry Low NOx burners. Good combustion practices	25.00	PPMVD	15% O2
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Carbon Monoxide	An oxidation catalyst for CO control for each CTG/HRSG unit, good combustion practices.	4.00	PPM	PPMVD@15%O2; 24-H AVG; SEE NOTES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Carbon Monoxide	Dry low NOx burners and good combustion practices.	9.00	LB/H	HOURLY EXCEPT DURING STARTUP/SHUTDOWN
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Carbon Monoxide	An oxidation catalyst for CO control for each CTG/HRSG unit; good combustion practices.	4.00	PPM	PPMVD@15%O2;24-H ROLL AVG; SEE NOTES

Table C-5. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - CO

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Carbon Monoxide	An oxidation catalyst for CO control for each CTG/HRSG unit; good combustion practices.	4.00	PPM	PPMVD@15%O2;24-H ROLL AVG; SEE NOTES
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaska's North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaska's Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Carbon Monoxide	Good Combustion Practices and burning clean fuels (NG)	15.00	PPMV @ 15% O2	3-HOUR AVERAGE

Table C-6. RBLC Search Results for Large Fuel Oil Fired Turbines (Simple-Cycle) - CO Emission Limit

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	PROCESS_NOTES	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	PRESQUE ISLE	MI	6/29/2011	Coal-fired power plant.		Turbine generator (EUBLACKSTART)	15.190	Diesel	540	MMBTU/H	This is a turbine generator identified in the permit as EUBLACKSTART. It has a throughput capacity of 540MMBTU/HR which equates to 102 MW. The maximum operation was based on 500 hours per year.	Carbon Monoxide		0.05	LB/MMBTU	TEST PROTOCOL
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water injection.	Carbon Monoxide	combustor designed for complete combustion and therefore minimizes emissions	20.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE

RBLC SEARCH RESULTS – VOC

Table C-7. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - VOC

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
PANDA SHERMAN POWER STATION	PANDA SHERMAN POWER LLC	GRAYSON	TX	2/3/2010	A combined-cycle power plant producing a nominal 600 MW with two Siemens SGT6-5000F (501F) or two GE 7FA gas turbines.	State permit 87225	Natural Gas-fired Turbines	16.210	Natural Gas	600	MW	2 Siemens SGT6-5000F or 2 GE Frame 7FA. Both capable of combined or simple cycle operation. 468 MMBtu/hr duct burners.	Volatile Organic Compounds (VOC)	Good combustion practices	1	PPMVD	@ 15% O2, 3-HR AVG, SIMPLE CYCLE MODE
DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SOUTHERN POWER COMPANY	JACKSON	GA	5/14/2010	PLANT DAHLBERG HAS PROPOSED TO CONSTRUCT AND OPERATE FOUR ADDITIONAL SIMPLE-CYCLE COMBUSTION TURBINES (SOURCE CODES: CT11-CT14) AND ONE FUEL OIL STORAGE TANK. THE PROPOSED PROJECT WILL HAVE A NOMINAL GENERATING CAPACITY OF 760 MW. THE FACILITY IS CURRENTLY PERMITTED TO OPERATE 10 DUAL-FUELED SIMPLE-CYCLE CTG's. AFTER THE EXPANSION, THE FACILITY WILL HAVE A TOTAL NOMINAL GENERATING CAPACITY OF 1530 MW.		SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	15.110	NATURAL GASE	1530	MW	THE PROCESS USES FUEL OIL FOR BACKUP AT THE RATE OF 2129 MMBUT/H	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	5	PPM@15%02	3 HOUR AVERAGE/CONTITION 3.3.24
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	natural gas	800	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Volatile Organic Compounds (VOC)	Good Combustion Control and Catalytic Oxidation (CatOx)	2.50	PPMVD AT 15% O2	AVE OVER STACK TEST LENGTH
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	7/22/2010	Combustion turbine power plant	New power plant consisting of 7 combustion turbines	Three simple cycle combustion turbines	15.110	natural gas	800	MMBTU/H	Three GE, LMS100PA, natural gas-fired, simple cycle CTG rated at 799.7 MMBtu per hour each,based on HHV.	Volatile Organic Compounds (VOC)	Good Combustion Control and Catalytic Oxidation (CatOx)	2.50	PPMVD AT 15% O2	AVE OVER STACK TEST LENGTH
PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	HUDSON	NJ	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION IS AN EXISTING ELECTRICITY GENERATING STATION.	This project consists of six new identical General Electric LM6000 sprint simple cycle combustion turbines burning natural gas. Each turbine will have a heat input rate of 485 million British thermal units per hour (MMBtu/hr) based on the high heating value of fuel (HHV). The combined maximum electricity generated by the six turbines will be 294 MW based on 2,978 hours of operation per turbine per year. All six new turbines will have water injection along with Selective Catalytic Reduction (SCR) systems to reduce Nitrogen Oxide (NOx) emissions and an oxidation catalyst to reduce Carbon Monoxide (CO) emissions	SIMPLE CYCLE TURBINE	15.110	Natural Gas	8,940,000	MMBtu/year (HHV)	Throughput <= 8.94xE6 MMBtu/year (HHV) combined for all six gas turbines. The 6 turbines are identical LM6000 simple cycle combustion turbines.	Volatile Organic Compounds (VOC)	Oxidation Catalyst and good combustion practices, use of natural gas.	4.00	PPMVD@15% O2	AVERAGE OF THREE TESTS
CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	CALCASIEU	LA	12/21/2011	320 MW POWER PLANT COMPRISED OF 2 NATURAL GAS-FIRED SIMPLE CYCLE COMBUSTION TURBINES.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD TRIGGERED DUE TO RELAXATION OF A FEDERALLY-ENFORCEABLE CONDITION LIMITING POTENTIAL EMISSIONS BELOW MAJOR STATIONARY SOURCE THRESHOLDS.	TURBINE EXHAUST STACK NO. 1 & NO. 2	15.110	NATURAL GAS	1,900	MM BTU/H EACH		Volatile Organic Compounds (VOC)	DRY LOW NOX COMBUSTORS	7.00	LB/H	HOURLY MAXIMUM
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE LM6000PC SPRINT Simple cycle combustion turbine	15.110	Pipeline quality natural gas	405	MMBTU/hr		Volatile Organic Compounds (VOC)	utilize efficient combustion/design technology	5.80	LB/HR	AT FULL LOAD
WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	LYON	KS	3/18/2013	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	This PSD permit with tracking number C-10656 is a modification of PSD permits C-9132 (issued on 5/5/2011) and C-7072 (issued 4/17/2007).	GE 7FA Simple Cycle Combustion Turbine	15.110	Pipeline quality natural gas	1,780	MMBTU/HR		Volatile Organic Compounds (VOC)	will utilize efficient combustion/design technology	3.20	LB/HR	AT FULL LOAD
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1,690	MMBTU/H		Volatile Organic Compounds (VOC)	Oxidation catalyst; Limit the time in startup or shutdown.	-		
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1,690	MMBTU/H		Volatile Organic Compounds (VOC)	Oxidation catalyst; Limit the time in startup or shutdown.	-		
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	4/22/2014	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	In this project, 24 peaking turbines from the Lauderdale facility are being replaced with five 200 MW combustion turbines at Lauderdale. The turbines will fire primarily natural gas, but may also fire ULSD fuel oil. Triggers PSD for NOx, PM, CO, VOC, and GHG. GHG permit issued by US EPA Region 4. Technical evaluation available at http://arm-permit2k.dep.state.fl.us/nontv/0110037.011.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural gas	2,000	MMBtu/hr (approx)	Throughput could vary slightly (+/- 120 MMBtu/hr) depending on final selection of turbine model and firing of natural gas or oil. Primary fuel is expected to be gas. Each turbine limited to 3300 hrs per rolling 12-month period. Of these 3300 hrs, no more than 500 may use ULSD fuel oil.	Volatile Organic Compounds (VOC)	Good combustion practice	3.77	LB/H	THREE ONE-HR RUNS (NATURAL GAS)
ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	GRIMES	TX	9/22/2014	The proposed project is to construct and operate the RPGS comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the model of combustion turbine (CT) selected. The applicant is considering three models of CTs; one model will be selected and the permit revised to reflect the selection before construction begins. The three CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F.		(2) simple cycle turbines	15.110	natural gas	600	MW	The three possible CT models are: (1) General Electric 7FA.04; (2) General Electric 7FA.05; or (3) Siemens SGT6- 5000F. will operate 2,920 hours per year at full load for each CT	Volatile Organic Compounds (VOC)	good combustion	1.40	PPMVD	@15% O2 GE OPTION
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/12/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine & Generator	15.110	natural gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Volatile Organic Compounds (VOC)	Good combustion practices	2.00	PPMVD @ 15% O2	
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	10/9/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	natural gas	230	MW	Siemens Model SGT6-5000 F5ee â€“ 230 MW or Second turbine option: General Electric Model 7FA.05TP â€“ 227 MW	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices.	1.40	PPMV	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	NACOGDOCHES	TX	10/14/2015	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).		Natural Gas Simple Cycle Turbine (>25 MW)	15.110	natural gas	232	MW	One Siemens F5 simple cycle combustion turbine generator	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices.	2.00	PPMVD @ 15% O2	

Table C-7. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - VOC

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
DECORDOVA STEAM ELECTRIC STATION	DECORDOVA II POWER COMPANY LLC	HOOD	TX	3/8/2016	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE). Simple cycle operations limited to 2,500 hr/yr.	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	2.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines > 25 MW	15.110	natural gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Volatile Organic Compounds (VOC)	good combustion practices	2.00	PPM	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	2.00	PPM	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	natural gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Volatile Organic Compounds (VOC)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	5.40	LB/H	
BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2,143,980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Volatile Organic Compounds (VOC)	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2.00	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	HUDSON	NJ	8/26/2016	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	The facility has eight existing simple cycle combustion turbines Rolls Royce Trent turbine 64 MW each. This permit allows the construction and operation of two more Rolls Royce Trent (WLE) simple cycle combustion turbines 66 MW each. The turbines will be dual fired, with natural gas as primary fuel and ultra low sulfur distillate oil with less than or equal to 15% sulfur by weight. The turbines will have SCR and Oxidation catalyst for removal of NOx, CO and VOC.	Simple Cycle Stationary Turbines firing Natural gas	15.110	Natural Gas	2,143,980	MMBTU/YR	The Siemens/Rolls Royce Trent 60 wet low emissions (WLE) combustion turbine generators (CTGs) will each have a maximum heat input rate while combusting natural gas of 643 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, at International Organization for Standardization (ISO) conditions of 59 degrees Fahrenheit (Â°F) and 60% relative humidity, generating 66 MW. The maximum heat input rate on ULSD at ISO condition would be 533.50 MMBtu/hr (HHV). Each of the CTG will be equipped with Water Injection and Selective Catalytic Reduction System (SCR) to control Nitrogen Oxide (NOx) emissions and Oxidation Catalyst to control Carbon Monoxide (CO) and Volatile Organic Compounds (VOC) emissions. The CTGs will have continuous emissions monitoring systems (CEMs) for NOx and CO.	Volatile Organic Compounds (VOC)	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2.00	PPMVD@15% O2	3 H ROLLING AV BASED ON ONE H BLOCK AV
PUENTE POWER		VENTURA	CA	10/13/2016	Utility		Gas turbine	15.110	Natural gas	262	MW		Volatile Organic Compounds (VOC)		2.00	PPMVD AS METHANE	1 HOUR@15%O2
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	a facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	natural gas	1,069	mm btu/hr		Volatile Organic Compounds (VOC)	good combustion practices and fueled by natural gas	1.60	PPMVD	@15%O2
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	natural gas	228	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices	2.00	PPMVD	145% O2
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines	15.110	natural gas	920	MW	4 identical units, each limited to 2500 hours of operation per year	Volatile Organic Compounds (VOC)	Good combustion practices	2.00	PPMVD	
JACKSON COUNTY GENERATORS	SOUTHERN POWER	JACKSON	TX	1/26/2018	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine		Combustion Turbines MSS	15.110	NATURAL GAS	-			Volatile Organic Compounds (VOC)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.06	TON/YR	
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	15.110	Natural Gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	15.110	natural gas	2,201	MM BTU/hr	Commissioning is a one-time event which occurs after construction and is not anticipated to exceed 180 days.	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		

Table C-7. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - VOC

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2,201	MM BTU/hR	Limited to 600 hr/yr	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2,201	MM BTU/hr	limited to 600 hr/yr	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2,201	MM BTU/hr	Normal operations are based on 7000 hours per year	Volatile Organic Compounds (VOC)	Good combustion practices & use of pipeline quality natural gas	-		
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	natural gas	540	mm btu/hr		Volatile Organic Compounds (VOC)	Good Combustion Practices and Use of low sulfur facility fuel gas	2.00E-03	LB/MM BTU	HHV
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.40	PPMV	3 HOUR AVERAGE
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.40	PPMV	3 HOUR AVERAGE
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.40	PPMV	3 HOUR AVERAGE
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	NATL GAS	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Volatile Organic Compounds (VOC)	Good combustion practices	2.00	PPMVD	15% O2
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control and good combustion practices.	3.00	PPM	PPMVD@15%O2; HOURLY; SEE NOTES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3.00	PPM	PPMVD@15%O2; HOURLY EXC.START/SHUT; NOTE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control and good combustion practices.	3.00	PPM	PPMVD@15%O2; HOURLY; SEE NOTES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/H natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Volatile Organic Compounds (VOC)	Good combustion practices.	5.00	LB/H	HOURLY EXCEPT DURING STARTUP/SHUTDOWN

Table C-7. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - VOC

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3.00	PPM	PPMVD@15%O2; HOURLY EXC.START/SHUT; NOTE
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskaâ€™s Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Volatile Organic Compounds (VOC)	Good Combustion Practices and burning clean fuels (NG)	2.20E-03	LB/MMBTU	3-HOUR AVERAGE
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskaâ€™s Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Volatile Organic Compounds (VOC)	Good Combustion Practices and burning clean fuels (NG)	2.20E-03	LB/MMBTU	3-HOUR AVERAGE

Table C-8. RBLC Search Results for Large Fuel Oil Fired Turbines (Simple-Cycle) - VOC

Facility Name	Corporate or Company Name	Facility County	State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel	Throughput	Throughput Units	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 1 Average Time Condition
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water injection.	Volatile Organic Compounds (VOC)	combustor designed for complete combustion and therefore minimizes emissions	3.30	LB/H	

RBLC SEARCH RESULTS – GHG

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
YORK GENERATION FACILITY	YORK PLANT HOLDINGS, LLC	YORK COUNTY	PA	3/1/2012	This plan approval will allow for the construction and temporary operation of two new combustion turbines at the facility.		COMBUSTION TURBINE, DUAL FUEL, T01 and T02 (2 Units)	15.900	Natural Gas	634	MMBTU/H	The combined number of hours of operation for both turbines shall not exceed 6000 hours per each consecutive 12-month period. The combined number of hours of distillate fuel oil firing for both turbines shall not exceed 1700 hours per each consecutive 12-month period. The liquid distillate fuel oil fired in the combustion turbines shall be ultra low sulfur kerosene - maximum sulfur content of 15 ppm or ultra low sulfur diesel (ULSD) - maximum sulfur content of 15 ppm (as defined in ASTM standard D975 Table 1). In addition to operational limits, air emissions will be minimized by Catalytic Oxidizer for CO control and Water injection followed by Selective Catalytic Reduction system utilizing aqueous ammonia for NOx control.	Carbon Dioxide Equivalent (CO2e)		1330	LB/MWH	30 DAY ROLLING
PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	OTAY MESA	CA	11/19/2012	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	NOTE: PERMIT ISSUED 11/19/2012. ENVIRONMENTAL APPEALS BOARD REMANDED THE PM BACT ANALYSIS TO REGION 9 ON 8/2/2013. FINAL PERMIT ISSUED ON 2/28/2014. ONE PETITION FILED IN 9TH CIRCUIT FEDERAL COURT CHALLENGING THE FINAL PERMIT DECISION. THIS LAWSUIT WAS DISMISSED ON 6/17/2014 IN RESPONSE TO PETITIONERS MOTION FOR VOLUNTARY DISMISSAL.	COMBUSTION TURBINES (NORMAL OPERATION)	15.110	NATURAL GAS	300	MW	Three simple cycle combustion turbine generators (CTG). Each CTG rated at 100 MW (nominal net).	Carbon Dioxide Equivalent (CO2e)		1328	LB/MW-H	GROSS OUTPUT
R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	MORTON	ND	2/22/2013	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.		Combustion Turbine	15.110	Natural gas	986	MMBTU/H	Turbine is a GE Model PG 7121 (7EA) used as a peaking unit.	Carbon Dioxide Equivalent (CO2e)		413198	TONS/12 MONTH	12 MONTH ROLLING TOTAL
PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	WILLIAMS	ND	5/14/2013	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	The permit was for the addition of 2 turbines to the station. Since a synthetic minor limit was relaxed for the first unit, BACT was required for all three turbines.	Natural gas-fired turbines	15.110	Natural gas	451	MMBTU/H	Rating is for each turbine.	Carbon Dioxide Equivalent (CO2e)		243147	T/12 MON ROLL TOTAL	12 MONTH ROLLING TOTAL/EACH UNIT
LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	MCKENZIE	ND	9/16/2013	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.		Natural Gas Fired Simple Cycle Turbines	15.110	Natural gas	412	MMBTU/H	The heat input is for a single unit.	Carbon Dioxide Equivalent (CO2e)	High efficiency turbines	220122	TONS	12 MONTH ROLLING TOTAL
RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MONTCALM	MI	11/1/2013	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Other facility-wide pollutants not listed below (tpy): PM10=211.19+ PM2.5=205.24+ Lead=0.0027+ CO2e=5,398,441+ Sulfuric Acid Mist=5.67+	FG-CTG1-4 Natural gas fueled combined cycle combustion turbine generators (CTG)	15.210	Natural gas	2147	MMBTU/H	FG-CTG1-4: Four natural gas fired CTGs with each turbine containing a heat recovery steam generator (HRSG) to operate in combined cycle. Two CTGs (with HRSGs) are connected to one steam turbine generator. Each CTG is equipped with a dry low NOx (DLN) burner, a selective catalytic reduction (SCR) system, and a catalytic oxidation system. The throughput capacity is 2,147 MMBtu/hr for each CTG. The turbines are existing simple cycle turbines that will be retrofit to be combined cycle units.	Carbon Dioxide Equivalent (CO2e)	Good combustion practices/energy efficiency	1000	LB/MW-H	12-MONTH ROLLING AVERAGE
RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MONTCALM	MI	11/1/2013	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Other facility-wide pollutants not listed below (tpy): PM10=211.19+ PM2.5=205.24+ Lead=0.0027+ CO2e=5,398,441+ Sulfuric Acid Mist=5.67+	FG-CTG/DB1-4 Natural gas fueled combined cycle combustion turbine generators; duct burner on HRSG	15.210	Natural gas	2807	MMBTU/H	Four natural gas-fired CTGs with each turbine containing a heat recovery steam generator (HRSG) to operate in combined cycle. The two CTGs (with HRSGs) are connected to one steam turbine generator. Each CTG is equipped with a dry low NOx (DLN) burner and a selective catalytic reduction (SCR) system, and a catalytic oxidation system. Additionally, the HRSG is operated with a natural gas fired duct burner during supplemental firing. The turbines are existing simple cycle turbines which will be retrofit to be combined cycle. Operational restriction is 4000 hrs/year that each DB can operate.	Carbon Dioxide Equivalent (CO2e)	Good combustion practices/energy efficiency	1000	LB/MW-H	12-MONTH ROLLING AVERAGE

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	MULTNOMAH	OR	3/5/2014	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.		GE LMS-100 combustion turbines, simple cycle with water injection	15.110	natural gas	1690	MMBTU/H		Carbon Dioxide Equivalent (CO2e)	Thermal efficiency Clean fuels	1707	LB OF CO2 /GROSS MWH	365-DAY ROLLING AVERAGE
INDECK WHARTON ENERGY CENTER	INDECK WHARTON, LLC	WHARTON	TX	5/12/2014	Indeck proposes to construct a peaking power plant, the Indeck Wharton Energy Center, generally located south of Danevang, Texas. To meet the anticipated demand for peak power, Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be either General Electric (GE) 7FA.05 or Siemens SGT6-5000F(5). The GE 7FA.05 has a base-load electric power output of approximately 213 megawatts (MW, net nominal), and the Siemens SGT6-5000F(5) has a base-load electric power output of approximately 225 MW (net nominal). This project also proposes to install one emergency diesel generator, one diesel fire water pump, one natural gas pipeline heater, and other auxiliary equipment.	The Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project.	Simple Cycle Combustion Turbine, GE 7FA.05	15.110	Pipeline Natural Gas	0		Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be either General Electric (GE) 7FA.05 or Siemens SGT6-5000F(5). The GE 7FA.05 has a base-load electric power output of approximately 213 megawatts (MW, net nominal), and the Siemens SGT6-5000F(5) has a base-load electric power output of approximately 225 MW (net nominal).	Carbon Dioxide Equivalent (CO2e)		1276	LB CO2/MWHR (GROSS)	2,500 OPERATIONAL HR ROLLING DAILY/CT
INDECK WHARTON ENERGY CENTER	INDECK WHARTON, LLC	WHARTON	TX	5/12/2014	Indeck proposes to construct a peaking power plant, the Indeck Wharton Energy Center, generally located south of Danevang, Texas. To meet the anticipated demand for peak power, Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be either General Electric (GE) 7FA.05 or Siemens SGT6-5000F(5). The GE 7FA.05 has a base-load electric power output of approximately 213 megawatts (MW, net nominal), and the Siemens SGT6-5000F(5) has a base-load electric power output of approximately 225 MW (net nominal). This project also proposes to install one emergency diesel generator, one diesel fire water pump, one natural gas pipeline heater, and other auxiliary equipment.	The Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project.	Simple Cycle Combustion Turbine, SGT-5000F(5)	15.110	Pipeline Natural Gas	0		Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be either General Electric (GE) 7FA.05 or Siemens SGT6-5000F(5). The GE 7FA.05 has a base-load electric power output of approximately 213 megawatts (MW, net nominal), and the Siemens SGT6-5000F(5) has a base-load electric power output of approximately 225 MW (net nominal).	Carbon Dioxide Equivalent (CO2e)		1337	LB CO2/MWHR (GROSS)	2500 OPERATIONAL HR ROLLING DAILY/CT
PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	PUEBLO	CO	5/30/2014	Power generation facility		Turbine - simple cycle gas	15.110	natural gas	375	MMBTU/H	One (1) General Electric, simple cycle, gas turbine electric generator, Unit 6 (CT08), model: LM6000, SN: N/A, rated at 375 MMBtu per hour.	Carbon Dioxide Equivalent (CO2e)	Good Combustion Control	1600	LB/MW H GROSS	ROLLING 365-DAY AVE
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	8/1/2014	Invenergy proposes to construct a 330 MW peak power plant (known as the Ector County Energy Center Plant (ECEC)), located in Goldsmith, Ector County, Texas. With this proposed project, Invenergy plans to construct two natural gas-fired simple-cycle turbines, General Electric (GE) Model 7FA.03, and associated equipment, a fire water pump engine, a natural gas-fired dew-point heater, and two circuit breakers. For the purposes of this proposed permitting action, GHG emissions are permitted for the two turbines, the fire water pump engine, the natural gas-fired dew-point heater, and the circuit breakers, as well as for fugitive emissions, and maintenance, startup and shutdown emissions.	Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project.	Simple Cycle Combustion Turbine, GE 7FA.03	15.110	Natural Gas	11707	Btu/kWh (HHV)		Carbon Dioxide Equivalent (CO2e)		1393	LB CO2/MWHR (GROSS)	2500 OPERATIONAL HR ROLLING DAILY/CT
ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	ECTOR	TX	8/1/2014	Invenergy proposes to construct a 330 MW peak power plant (known as the Ector County Energy Center Plant (ECEC)), located in Goldsmith, Ector County, Texas. With this proposed project, Invenergy plans to construct two natural gas-fired simple-cycle turbines, General Electric (GE) Model 7FA.03, and associated equipment, a fire water pump engine, a natural gas-fired dew-point heater, and two circuit breakers. For the purposes of this proposed permitting action, GHG emissions are permitted for the two turbines, the fire water pump engine, the natural gas-fired dew-point heater, and the circuit breakers, as well as for fugitive emissions, and maintenance, startup and shutdown emissions.	Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project.	Simple Cycle Combustion Turbine-MSS	15.110	Natural Gas	0			Carbon Dioxide Equivalent (CO2e)		21	TON CO2E/EVENT	EACH MSS EVENT

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS, L.P.	GUADALUPE	TX	12/2/2014	GPP proposes to add two (2) new gas-fired simple-cycle combustion turbines of 227 MW (nominal) electric generating capacity each to the 1,000 MW (nominal) existing major stationary source, Guadalupe Generating Station (GGS), located in Marion, Texas. The proposed project will provide peaking capacity at an existing natural gas fired combined cycle electric generating station. The two new natural gas-fired simple-cycle turbines are proposed to provide a fast ramp up for additional peaking capacity during peak electricity demand periods. In addition, the project also includes the installation of a firewater pump engine, circuit breakers and associated fugitive emissions.	The Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project. See CN600132120 and RN100225820	Simple Cycle Combustion Turbine Generator	15.110	Pipeline Natural Gas	10673	Btu/kWh	Natural gas-fired simple cycle combustion turbine generators (CTG) will be General Electric 7FA.05 (GE 7FA.05), each with a maximum base-load electric power output of 227 megawatts (MW, nominal). Combined gross heat rate limit of 10,279,456 MMBtu/yr.	Carbon Dioxide Equivalent (CO2e)		1293.3	LB CO2/MWHR (GROSS)	12-MONTH ROLLING AVERAGE (NORMAL OPER)
GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS, L.P.	GUADALUPE	TX	12/2/2014	GPP proposes to add two (2) new gas-fired simple-cycle combustion turbines of 227 MW (nominal) electric generating capacity each to the 1,000 MW (nominal) existing major stationary source, Guadalupe Generating Station (GGS), located in Marion, Texas. The proposed project will provide peaking capacity at an existing natural gas fired combined cycle electric generating station. The two new natural gas-fired simple-cycle turbines are proposed to provide a fast ramp up for additional peaking capacity during peak electricity demand periods. In addition, the project also includes the installation of a firewater pump engine, circuit breakers and associated fugitive emissions.	The Texas Commission on Environmental Quality is the permitting authority for the non-GHG emissions associated with this project. See CN600132120 and RN100225820	Simple Cycle Combustion Turbine Generator	15.110	Pipeline Natural Gas	10673	Btu/kWh	Natural gas-fired simple cycle combustion turbine generators (CTG) will be General Electric 7FA.05 (GE 7FA.05), each with a maximum base-load electric power output of 227 megawatts (MW, nominal). Combined gross heat rate limit of 10,279,456 MMBtu/yr.	Carbon Dioxide Equivalent (CO2e)		1293.3	LB CO2/MWHR (GROSS)	12-MONTH ROLLING AVERAGE (NORMAL OPER)
SABIC INNOVATIVE PLASTICS MT. VERNON, LC	SABIC INNOVATIVE PLASTICS MT. VERNON, LC	POSEY	IN	12/11/2014	PLASTIC MANUFACTURING PLANT		COMBUSTION TURBINE:COGEN	15.110	NATURAL GAS	1812	MMBTU/H		Carbon Dioxide Equivalent (CO2e)		937379	T/YR	
ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	HALE	TX	5/20/2015	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbines (CTG). Each turbine has a maximum electric output of 202 MW.		Simple Cycle Turbine Generator	15.110	natural gas	202	MW	3 additional GE 7F 5-Series Combustion Turbine Generators	Carbon Dioxide Equivalent (CO2e)	Energy efficiency, good design & combustion practices	1304	LB CO2/MWHR	
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed. Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators. Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1. Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 1 (4, identical) (P001, P002, P004, P005)	15.210	Natural gas	2022	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Carbon Dioxide Equivalent (CO2e)	high efficiency	7471	BTU/KW-H	HHV NET PER EACH CCT BLOCK. SEE NOTES.

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
ROLLING HILLS GENERATING, LLC		VINTON	OH	5/20/2015	Electrical services	Note: The proposed modification was not installed. Chapter 31 major modification to convert four of the existing five simple cycle peaking units, SW501F turbines nominally rated at 209 megawatts (MW) each, to combined cycle configuration consisting of two 2x1 combined cycle blocks, the addition of four heat recovery steam generators (HRSGs), each of which will be equipped with duct burners, and two steam turbine generators. Permit includes 2 options for the units. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner. Emissions increase noted below is for scenario 1. Scenario 2 = 5101.7 CO, 449.31 NOx, 346.8 PM and 600.62 VOC.	Combustion Turbines, Scenario 2 (4, identical) (P001, P002, P004, P005)	15.210	Natural gas	2144	MMBTU/H	Scenario 1 only. Other scenario added as separate process. Siemens Westinghouse Power Corp. SW501F, (Scenario 1: 200 MW, with 2022 MMBtu/hr input & 550 MMBtu/hr duct burner. Scenario 2: 207.5 MW with 2144 MMbtu/hr input & 550 MMBtu/hr duct burner.) combined cycle natural gas fired turbine with Dry Low-NOX combusters, SCR and duct burner.	Carbon Dioxide Equivalent (CO2e)	high efficiency	7471	BTU/KW-H	HHV NET PER EACH CCT BLOCK. SEE NOTES.
LAUDERDALE PLANT	FLORIDA POWER & LIGHT	BROWARD	FL	8/25/2015	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Re-affirmed BACT determinations in Permit No. 0110037-011-AC. Also, new GHG BACT determination. Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0110037.013.AC.D.ZIP	Five 200-MW combustion turbines	15.110	Natural gas	2100	MMBtu/hr (approx)	Five simple cycle GE 7F.05 turbines. Max of 3390 hours per year per turbine. Of the 3390 hours per year, up to 500 hour may be on ULSD fuel oil.	Carbon Dioxide	Use of natural gas with restricted use of ULSD as backup fuel	1372	LB/MWH	NAT GAS OPERATION, 12- OR 36- MO ROLLING
FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	LEE	FL	9/10/2015	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will be replaced with two new GE 7F.05 turbines, each with nominal capacity of 200 MW	Technical evaluation available at https://arm-permit2k.dep.state.fl.us/nontv/0710002.022.AC.D.ZIP	Combustion Turbines	15.110	Natural gas	2262.4	MMBtu/hr gas	Two GE 7F.05 turbines, approximately 200 MW each. Natural-gas is primary fuel. Permitted 3390 hr/yr of operation, of which no more than 500 hr may be on fuel oil. Dry Low-NOx, with wet injection for oil firing.	Carbon Dioxide Equivalent (CO2e)	Use of low-emitting fuel and efficient turbine	1374	LB CO2E / MWH	FOR NATURAL GAS OPERATION
SR BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER	HARRIS	TX	9/15/2015	Electric Generating Utility: The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.		Simple cycle turbines greater than 25 megawatts (MW) firing natural gas	15.110	natural gas	359	MW	4 options: General Electric (GE) 7HA 359 MW GE 7FA 215 MW Siemens SF5 (SF5) 225 MW Mitsubishi 501G (MHI510G) 263 MW	Carbon Dioxide		1232	LB /MW H	
CEDAR BAYOU ELECTRIC GENERATING STATION	NRG TEXAS POWER	CHAMBERS	TX	9/15/2015	Electric Generating Utility: The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	natural gas	359	MW	4 turbine options General Electric 7HA 359 MW GE 7FA 215 MW Siemens SF5 (SF5) 225 MW Mitsubishi 501G (MHI510G) 263 MW	Carbon Dioxide		1232	LB CO2/MWH	
SR BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER	HARRIS	TX	9/15/2015	Electric Generating Utility: The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.		Combined cycle and cogeneration turbines greater than 25 MW firing natural gas	15.210	natural gas	301	MMBTU/H	GE 7HA 359 MW +a 301 million British thermal units per hour (MMBtu/hr) duct burner (DB) GE7FA 215 MW + a 523 MMBtu/hr DB SF5 225 MW + 688 MMBtu/hr DB MHI510G 263 MW + 686 MMBtu/hr DB	Carbon Dioxide		825	LB /MW H	
CEDAR BAYOU ELECTRIC GENERATING STATION	NRG TEXAS POWER	CHAMBERS	TX	9/15/2015	Electric Generating Utility: The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.		Combined cycle and cogeneration turbines greater than 25 MW	15.210	natural gas	301	MMBTU/H	4 turbines options GE 7HA 359 MW +a 301 million British thermal units per hour (MMBtu/hr) duct burner (DB) GE7FA 215 MW + a 523 MMBtu/hr DB SF5 225 MW + 688 MMBtu/hr DB MHI510G 263 MW + 686 MMBtu/hr DB	Carbon Dioxide		825	LB CO2/MWH	

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	HILL	TX	11/10/2015	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.		Simple cycle turbines greater than 25 megawatts (MW)	15.110	natural gas	230	MW	Siemens Model SGT6-5000 F5 230 MW or Second turbine option: General Electric Model 7FA.05TP 227 MW	Carbon Dioxide Equivalent (CO2e)		1398	LB/MWH	
CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	GUADALUPE	TX	11/13/2015	Navasota South Peakers Operating Company II LLC proposes to install three new natural gas fired combustion turbine generators (CTGs). Each CTG will be a General Electric 7FA.04 model that can produce approximately 183 Megawatts (MW) each based upon the manufacturers projected output at baseload operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Dioxide Equivalent (CO2e)	Low carbon fuel, good combustion, efficient combined cycle design	1461	LB/MW H	
UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	NIXON	TX	12/16/2015	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturers output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	MW	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Dioxide Equivalent (CO2e)		1461	LB/MW H	
VAN ALSTYNE ENERGY CENTER	NAVASOTA NORTH PEAKERS OPERATING COMPANY I, LLC.	GRAYSON	TX	1/13/2016	Navasota North Peakers Operating Company I, LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.		Simple Cycle Turbine	15.110	natural gas	183	mw	The CTGs will be three General Electric 7FA.04 (~183 MW each for a total of 550 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year. The new CTGs will use dry low-NOx (DLN) burners and may employ evaporative cooling for power enhancement.	Carbon Dioxide		1461	LB/MWH	
NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER	NACOGDOCHES	TX	3/1/2016	Electric Generation		Combined Cycle Cogeneration	15.110	natural gas	232	MW		Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices	1316	LB/MW HR	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Large Combustion Turbines > 25 MW	15.110	natural gas	232	MW	4 Simple cycle CTGs, 2,500 hr/yr operational limitation. Facility will consist of either 232 MW (Siemens) or 220 MW (GE)	Carbon Dioxide Equivalent (CO2e)	good combustion practiceS	1341	LB/MW H	
NECHES STATION	APEX TEXAS POWER LLC	CHEROKEE	TX	3/24/2016	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.		Combined Cycle & Cogeneration	15.210	natural gas	231	MW	2 CTGs to operate in simple cycle & combined cycle modes. 231 MW (Siemens) or 210 MW (GE) Simple cycle operations limited to 2,500 hr/yr.	Carbon Dioxide Equivalent (CO2e)	GOOD COMBUSTION PRACTICES	924	LB/MWH	
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple cycle turbine	15.110	natural gas	171	MW	Each combustion turbine is limited to 2,920 hours of annual operation, including startup and shutdown hours.	Carbon Dioxide Equivalent (CO2e)		1434	LB/MWH	
INVENERGY NELSON EXPANSION LLC	INVENERGY	LEE	IL	9/27/2016	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.		Two Simple Cycle Combustion Turbines	15.110	Natural Gas	190	MW	Two simple cycle combustion turbines used for peaking purposes and fired primarily on natural gas with ULSD as a secondary fuel.	Carbon Dioxide Equivalent (CO2e)	Turbine-generator design and proper operation	0		
DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	HANAOVER	VA	10/4/2016	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines were permitted in a PSD permit originally issued on May 4, 1990 and last amended on August 3, 2005. The 190.5 MW simple cycle combustion turbine (CT-1) was added in a separate PSD permit dated April 7, 2000 and last amended on September 30, 2013.	DEC is proposing to add two GE 7FA simple cycle combustion turbines (CT-2 and CT-3) at the Doswell Energy Center. DEC is moving CT-2 and CT-3 from an existing permitted site in Desoto, Florida. They are both GE Frame 7FA Combustion Turbines that are very similar in age and capability to the DEC CT-1 (GE 7FA.03). The CT-2 and CT-3 maximum heat input assumed for natural gas firing is 1,961.0 MMBtu/hr (HHV).	Two (2) GE 7FA simple cycle combustion turbines	15.110	Natural Gas	1961	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	Good combustion, maintenance and use of active combustion dynamic monitoring systems.	0		

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
DECORDOVA STEAM ELECTRIC STATION (DECORDOVA STATION)	DECORDOVA II POWER COMPANY LLC	HOOD	TX	10/4/2016	two combustion turbines (CTGs) authorized to operate in simple cycle or combined cycle.	The simple cycle operations were issued in 2013, but the combined cycle criteria pollutant PSD permit / state amendment was issued on March 8, 2016. This GHG initial review is linked to the 2016 action which added combined cycle capability, it does not apply to the simple cycle operations which were authorized in 2013.	Combined Cycle and Cogeneration (>25 MW)	15.210	natural gas	213	MW	Two turbine options: GE 7FA [210 megawatts (MW)] or Siemens 5000F (231MW)	Carbon Dioxide Equivalent (CO2e)	good combustion practices and firing low carbon fuel.	966	LB/MW H	
WAVERLY FACILITY	PLEASANTS ENERGY, LLC	PLEASANTS	WV	1/23/2017	300 MW, natural gas fired, simple cycle peaking power facility	In this permitting action PSD only applies to the modified combustion turbines based on the relaxation of an original synthetic minor permit issued in 1999. Project also involves previous installation of turbo-charging. All BACT emission limits are given without turbocharging and startup/shutdown emissions are not included. Please contact above engineer for more information. There are two identical turbines but only one is listed.	GE Model 7FA Turbine	15.110	Natural Gas	1571	mmbtu/hr	There are two identical units at the facility.	Carbon Dioxide	Use of Natural Gas, Selection of GE7FA	1300	LB/MW-HR	NATURAL GAS
CAMERON LNG FACILITY	CAMERON LNG LLC	CAMERON	LA	2/17/2017	a facility to liquefy natural gas for export (5 trains)	Permit PSD-LA-766, dated 10/1/13 for liquefaction trains 1,2, and 3 Permit PSD-LA-766(M1), dated 6/26/14, for minor changes; Permit PSD-LA-766(M2), dated 3/3/16, for train 4 and 5	Gas turbines (9 units)	15.110	natural gas	1069	mm btu/hr		Carbon Dioxide Equivalent (CO2e)	good combustion practices and fueled by natural gas; Use high thermal efficiency turbines	0		
GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY		TX	4/28/2017	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.		Simple Cycle Turbine	15.110	natural gas	227.5	MW	Four Siemens SGT6-5000F5 natural gas fired combustion turbines	Carbon Dioxide Equivalent (CO2e)	Pipeline quality natural gas; limited hours; good combustion practices	1300	LB/MW H	
JACKSON COUNTY GENERATING FACILITY	SOUTHERN POWER	JACKSON	TX	6/30/2017	simple cycle electric generation		Simple Cycle Turbines	15.110	natural gas	920	MW	The facility will consist of four Siemens F5 model (~230 megawatts (MW) each for a total of 920 MW), operating as peaking units in simple cycle mode. Each turbine will be limited to 2,500 hours of operation per year.	Carbon Dioxide Equivalent (CO2e)	energy efficiency designs, practices, and procedures, CT inlet air cooling, periodic CT burner maintenance and tuning, reduction in heat loss, i.e., insulation of the CT, instrumentation and controls	1316	LB/MW HR	
MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	YOAKUM	TX	8/16/2017	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.		Simple Cycle Turbine	15.110	NATURAL GAS	162.8	MW	Unit 6 Turbine is limited to 3000 hours per year.	Carbon Dioxide Equivalent (CO2e)	Pipeline quality natural gas and good combustion practices	120	LB/MMBTU	
WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	PLEASANTS	WV	3/13/2018	300 MW Sinple-Cycle Peaking Plant	Modification to existing PSD Permit (R14-0034, RBLC Number WV-0027) to add advanced gas path technology to the turbines that was defined as a change in the method of operation that resulted a major modification to the turbines.	GE 7FA.004 Turbine	15.110	Natural Gas	167.8	MW	This one entry is for both turbines as they are the same. Each turbine, after this modification, is a nominal 167.8 MW GE Model 7FA.004. Has oil-fire backup.	Carbon Dioxide Equivalent (CO2e)	Use of natural gas & use of GE 7FA.004	0		
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 SUSD - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0019]	15.110	Natural Gas	2201	MM BTU/hR	Limited to 600 hr/yr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	120	LB/MM BTU	ANNUAL AVERAGE
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 SUSD - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning/Runback) [EQT0020]	15.110	Natural Gas	2201	MM BTU/hr	limited to 600 hr/yr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	120	LB/MM BTU	ANNUAL AVERAGE
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG01 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hrs/yr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	50	KG/GJ	ANNUAL AVERAGE
WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	WSHINGTON PARISH	LA	5/23/2018	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	Application Accepted Date reflects date of administrative completeness.	CTG02 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	15.110	Natural Gas	2201	MM BTU/hr	Normal operations are based on 7000 hours per year	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	50	KG/GJ	ANNUAL AVERAGE

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	CALCASIEU	LA	7/10/2018	Propose a new facility to liquefy natural gas for export		Compressor Turbines (20)	15.110	natural gas	540	mm btu/hr		Carbon Dioxide Equivalent (CO2e)	Use Low Carbon Fuel, Energy Efficiency Measures, and Good Combustion Practices	0		
CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	CAMERON	LA	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Application Received September 2, 2015.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	15.110	Natural Gas	927	MM BTU/h		Carbon Dioxide Equivalent (CO2e)	Exclusively combust low carbon fuel gas, good combustion practices, good operation and maintenance practices, and insulation	1426146	T/YR	ANNUAL TOTAL
RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	CAMERON	TX	12/17/2018	Natural gas processing and liquefied natural gas (LNG) export terminal		Refrigeration Compression Turbines	15.110	NATL GAS	967	MMBTU/HR	Twelve General Electric Frame 7EA simple cycle combustion turbines to serve as drivers for refrigeration and compression at the site. There are six process trains and there are two turbines per train. One each of the pairs of turbines has a downstream heat exchanger in the exhaust stream. The heat exchanger heats oil in a closed circuit for process uses elsewhere in the natural gas liquefaction system.	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and use of pipeline quality natural gas.	0		
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Carbon Dioxide Equivalent (CO2e)	low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	430349	T/YR	12-MO ROLLING TIME PERIOD
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2 is a nominally rated 667 MMBTU/H natural gas fired CTG coupled with a HRSG. The HRSG is equipped with a natural gas fired duct burner rated at 204 MMBTU/h to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a DLNB, SCR and oxidation catalyst.	Carbon Dioxide	low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	1000	LB/MW-H	GROSS ENERGY OUTPUT; 12-OPERATING MO AVG
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Carbon Dioxide Equivalent (CO2e)	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	430349	T/YR	12-MO ROLLING TIME PERIOD
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/21/2018	Natural gas combined-cycle power plant.	The proposed new plant will be replacing the electrical generating capacity of both BWL's existing coal-fired power plants. BWL intends to retire those coal-fired power plants from service by 2025. However, before they can be retired, the new natural gas power plant must be operational. Emissions in the area will increase for a short period if the new combined-cycle plant is built. However, there will be overall reductions in emissions when the existing coal fired power plants are taken out of service.	EUCTGHRSG1--A 667 MMBTU/H NG fired combustion turbine generator coupled with a heat recovery steam generator (HRSG)	15.210	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 204 MMBTU/hr to provide heat for additional steam production. The CTG is capable of operating in combined-cycle mode where the exhaust is routed to the HRSG or in simple-cycle mode where the HRSG is bypassed. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with a dry low NOx burner (DLNB), selective catalytic reduction (SCR) and oxidation catalyst.	Carbon Dioxide	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	1000	LB/MW-H	12-OPERATING MO. AVG; SEE NOTES

Table C-9. RBLC Search Results for Large Natural Gas Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	NORTH SLOPE BOROUGH	AK	8/13/2020	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskas North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaskas Kenai Peninsula for export in foreign commerce. The emissions units at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.		Six (6) Simple Cycle Gas-Turbines (Power Generation)	15.110	Natural Gas	386	MMBtu/hr	EUs 25 -30 each provide 44 MW of power generation for the facility	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and clean burning fuel (NG)	117.1	LB/MMBTU	3-HOUR AVERAGE
ECTOR COUNTY ENERGY CENTER	ECTOR COUNTY ENERGY CENTER LLC	ECTOR	TX	8/17/2020	increase the hours of operation for the two simple cycle gas turbines		Simple Cycle Turbines	15.110	natural gas	0			Carbon Dioxide Equivalent (CO2e)	Best management practices and good combustion practices, clean fuel	1514	LB/MWHR	

Table C-10. RBLC Search Results for Large Fuel Oil Fired Turbines (Simple-Cycle) - GHG

Facility Name	Corporate or Company Name	Facility County	Facility State	Permit Issuance Date	Facility Description	Permit Notes	Process Name	Process Type	Primary Fuel Type	Throughput	Throughput Unit	Process Notes	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition
HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	HILL	TX	4/7/2016	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).		Simple Cycle Turbine	15.190	ULTRA LOW SULFUR DIESEL	171	MW	LIQUID FUEL ONLY USED AS BACKUP TO NATURAL GAS Each combustion turbine is limited to 624,000 million Btu of annual firing because these are peaking units. Emission control firing ULSD adds water injection.	Carbon Dioxide Equivalent (CO2e)		1434	LB/MWH	

APPENDIX D. CONTROL COST ANALYSES

Table D-1. Potential Emissions from Combustion Turbine Systems

Pollutant Emissions	Emission Factor[1-2] (lb/MMBtu)	Maximum Annual Operating Capacity[3] (MMBtu/yr/turbine)	Maximum Annual Emissions for each Turbine[4] (tpy)
Natural Gas			
NO_X (Natural Gas)	3.00E-02	5,298,000	79.3
CO (Natural Gas)	1.82E-02		48.3
VOC (Natural Gas)	6.37E-03		16.9
CO_2 (Natural Gas)	116.98		309,870
Fuel Oil			
NO_X (Fuel Oil)	1.40E-01	945,000	66.0
CO (Fuel Oil)	4.05E-02		19.1
VOC (Fuel Oil)	1.59E-02		42.1
CO_2 (Fuel Oil)	163.05		77,042
Total NO_X Emissions (per turbine)			**145.4**
Total CO Emissions (per turbine)			**67.4**
Total VOC Emissions (per turbine)			**59.0**
Total CO_2 Emissions (per turbine)			**386,912**

1. Emission factors for natural gas based on current vendor guarantees of 9 ppm @ 15% O_2 for NO_X/CO and 1.4 ppm @ 15% O_2 for VOC.
2. Emission factors for fuel oil combustion are obtained from the proposed BACT limit selection.
3. Maximum Annual Operating Capacity anticipated for sustainable operation for one (1) turbine.

Natural Gas	1,766 MMBtu/hr
Fuel Oil	1,890 MMBtu/hr

4. Emissions (tpy) = EF (lb/MMBtu) * Maximum Annual Operating Capacity (MMBtu/yr) / 2,000 lb/ton

Table D-2. Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Capital Cost

Capital Cost Summary		Capital Cost
DIRECT COSTS		
PURCHASED EQUIPMENT COST (PEC)[1]	**PEC =**	**$11,303,389**
TOTAL DIRECT CAPITAL COST (DCC)[2]	**DCC =**	**$11,303,389**
INDIRECT COSTS[3]		
Engineering (10% of PEC)		$1,130,339
General Facilities (5% of PEC)		$565,169
Process Contingency (5% of PEC)		$565,169
TOTAL INDIRECT CAPITAL COST (ICC)	**ICC =**	**$2,260,678**
PROJECT CONTINGENCY (15% of ICC + DCC) (PC)[3]	**PC =**	**$2,034,610**
OTHER PREPRODUCTION COSTS		
Preproduction Cost (2% of (DCC+ ICC + PC))		$311,974
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC)	**TCI =**	**$15,910,650**

1. Based on data obtained for another project by Trinity Consultants from Black & Veatch in 2010, for a similarly sized unit. The purchased equipment cost was corrected for inflation to 2020 dollars.

2. Freight, instrumentation, initial catalyst charge, and direct installation costs are assumed to be included in the purchase cost.

3. U.S. EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction," Sixth Edition, October 2000.

Table D-3. Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Annual Cost

Annual Cost Summary				**Annual Cost**
DIRECT ANNUAL COSTS				
OPERATION AND MAINTENANCE[1]				
Maintenance (0.5% of TCI)				$79,553
REAGENT				
Requirement[3]	73 lb/hr at	$483.10 per ton[2]		$61,716
CATALYST				
Catalyst Replacement[3]				$1,784,746
Catalyst Life (years)				3.00
Annual Interest Rate (%)				7.00%
Future Worth Factor				0.381
Total Annual Catalyst Replacement Cost				$680,080
UTILITIES[4]				
Electricity	413.15 kW/hr at	$0.0638 per kW-hr		$92,257
TOTAL DIRECT ANNUAL COSTS (DAC)			**DAC =**	**$913,606**
INDIRECT OPERATING COSTS[1]				
Overhead (0% for SCR)				$0
Administrative Charges (0% of TCI)				$0
Property Taxes (0% of TCI)				$0
Insurance (0% of TCI)				$0
Capital Recovery (CRF x TCI)				
20 years @	7.00% interest	CRF[5] =	0.0944	$1,501,853
TOTAL INDIRECT ANNUAL COSTS (IAC)			**IAC =**	**$1,501,853**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)			**TAC=**	**$2,415,459**
Cost Effectiveness Summary				
Annual Control Cost ($)				**$2,415,459**
Pollutant to be Removed [NO_X] (tpy)[6]				**119.88**
CONTROL COST EFFECTIVENESS ($/ton)				**$20,150**

1. U.S. EPA CCM, Section 4, Chapter 2, "Selective Catalytic Reduction," Seventh Edition, June 2019.

2. Reagent cost taken from Appendix A.2.3 of U.S. EPA's *Petroleum Refinery Tier 2 BACT Analysis Report* dated January 16, 2001 (available at http://www.epa.gov/ttn/caaa/t1/memoranda/bactrpt.pdf). The $300/ton reagent cost from this document was corrected for inflation to 2020 dollars.

3. Catalyst replacement cost and ammonia flow rate based on data obtained for another project by Trinity Consultants which was provided by Cormetech in 2010, for a similarly sized unit. The catalyst replacement cost was corrected for inflation to 2020 dollars.

4. Based on power consumption and electricity cost equations in U.S. EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction," Sixth Edition, October 2000. Assumes a duct pressure drop of 2 inches of water, catalyst pressure drop of 0.75 inches of water, and three catalyst layers. Electricity price based on average retail price of electricity in Georgia in January through September 2019 for the industrial sector (www.eia.doe.gov).

5. Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the U.S. EPA CCM, Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology," Sixth Edition, January 2002.

6. NO_X emissions reductions based on the following controlled limits for units with SCR:

Gas Combustion	SCR Controlled NO_X Rate	2 ppm	@ 15% O_2	6.66E-03 lb/MMBtu	17.6 tpy
Fuel Oil Combustion	SCR Controlled NO_X Rate	5 ppm	@ 15% O_2	1.66E-02 lb/MMBtu	7.9 tpy

Table D-4. Oxidation Catalyst Economic Feasibility Assessment Calcs

Capital Cost Summary		Capital Cost
DIRECT COSTS[1]		
TOTAL PURCHASED EQUIPMENT COST (PEC)	**PEC =**	**$2,808,644**
(1) Purchased Equipment		
(a) Total Equipment[2]		**$2,380,207**
(b) Instrumentation (0.1 x [1a])		**$238,021**
(c) Sales taxes (0.03 x [1a])		**$71,406**
(d) Freight (0.05x [1a])		**$119,010**
TOTAL DIRECT INSTALLATION COST, DC	**DC =**	**$842,593**
(2) Direct Installation		
(a) Foundation (0.08 x PEC)		**$224,692**
(a) Handling (0.14 x PEC)		**$393,210**
(c) Electrical (0.04 x PEC)		**$112,346**
(d) Piping (0.02 x PEC)		**$56,173**
(e) Insulation (0.01 x PEC)		**$28,086**
(f) Painting (0.01 x PEC)		**$28,086**
TOTAL DIRECT COST (TDC)	**TDC =**	**$3,651,237**
INDIRECT COSTS[1]		
(3) Engineering (0.1 x PEC)		$280,864
(4) Construction (0.05 x PEC)		$140,432
(5) Contractor fees (0.1 x PEC)		$280,864
(6) Start-up (0.02 x PEC)		$56,173
(7) Performance test (0.01 x PEC)		$28,086
TOTAL INDIRECT COST (TIC)	**TIC =**	**$786,420**
PROJECT CONTINGENCY ((TDC + TIC)*0.1))[3]	**PC =**	**$443,766**
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC)[4]	**TCI =**	**$4,881,423**

1. General costing approach from EAPCCM = EPA Air Pollution Control Cost Manual, Seventh Edition, February 2018. Section 3, Chapter 2 (Incinerators and Oxidizers).
2. Oxidation Catalyst equipment cost per a letter from Michael G. Tritapoe (TVA) to Mr. James P. Johnston (TDEC) with BACT analysis for OC on simple cycle large frame combustion turbines, dated July 31, 2019.
3. Assumes a project contingency of 10%.
4. Total Capital Investment = Total Direct Cost + Total Indirect Cost + Project Contingency

Table D-5. Oxidation Catalyst Economic Feasibility Assessment Calcs

Annualized Cost		**Annual Cost**
TOTAL CAPITAL INVESTMENT, TCI	**TCI =**	**$4,881,423**
DIRECT ANNUAL COSTS[1]		
ANNUAL LABOR COST (1a + 1b)		**$9,600**
(1) Operating Labor		
(a) Operating Cost		$8,350
(b) Supervisor (0.15 x 1a)		1250
MAINTENANCE LABOR AND MATERIALS (2a +2b)		**$11,500**
(2) Maintenance		
(a) Labor		$5,750
(b) Material (100% of 1a)		$5,750
(3) Equipment Life		
(a) Interest Rate		7.00%
(b) CRF[2]		0.086
(c) Annual Cost[3]		$969,499
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$990,599**
INDIRECT ANNUAL COSTS		
(4) Overhead (0.6 x (AClabor + Maintenance Labor and Materials))		$12,660
(5) Administrative charges (0.02 x TCI)		$97,628
(6) Property Tax (0.01 x TCI)		$48,814
(7) Insurance (0.01 x TCI)		$48,814
(8) Capital Recovery (CRFx (TCI - 1.08*Annual Catalyst Cost))		$329,029
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$536,946**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)[4]	**TAC=**	**$1,527,545**
Cost Effectiveness Summary		
POLLUTANT TO BE REMOVED (CO) (tpy)[5]		**53.95**
POLLUTANT TO BE REMOVED (VOC) (tpy)[5]		**47.20**
COST EFFECTIVENESS ($/ton CO removed)		**$28,312**
COST EFFECTIVENESS ($/ton VOC removed)		**$32,360**

1. Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States, January 2021 (Stats last updated May 2019). Hourly rates for maintenance based on data for Industrial Machinery Installation, Repair, and Maintenance Workers (49-9040). Hourly rates for operators based on data for Power Plant Operators (51-8013): https://www.bls.gov/oes/current/oes_nat.htm.
   Operating Labor Cost = 3,500 hours of Operation/Labor = 0.5 hours/shift × Labor Rate ($38.16/hr) × (Operating Hours/8 hours/shift)
   Maintenance Labor Cost = 3,500 hours of Operation/Labor = 0.5 hours/shift × Labor Rate ($28.67/hr) × (Operating Hours/8 hours/shift)
2. The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For example, for a 25-year equipment life and a 7% interest rate, CRF = 0.086.
3. Based on 2003 EPA Economic Analysis (Conservatively no CPI or cost ratios used) https://www.epa.gov/sites/production/files/2020-07/documents/combustion-turbines_eia_neshap_final_08-2003.pdf
4. TOTAL ANNUAL COST = Direct Annual Costs + Indirect Annual Costs
5. CO/VOC emissions reduction conservatively assumes the oxidation catalyst will achieve an 80% control efficiency on the uncontrolled value in Table D-1.

Table D-6. Calculation of Project Power Output Changes

Parameters	Value
Annual CO_2 Captured (tpy)[1]	1,392,882
CO_2 Captured (kg/yr)[2]	1,263,603,225
Proposed Project Increase in Power Output (MW)[3]	48
Energy Used for Capture (kWh/kg CO_2 processed)[4]	0.354
Energy Used for Capture (kWh/yr)[5]	447,315,542
Energy Used for Capture (MWh/yr)	447,316
Power Output Before Project (MW)	680
Power Output After Project (without CCS)(MW)	728
Power Used for Capture if CCS included (MW)[6]	128
Power Output After Project (with CCS)(MW)	600

1. Presumes 90% capture of the CO_2 emissions based on the sustainable annual capacity of the facility.

2. CO_2 Captured (kg/yr) = CO_2 Captured (tpy) * 2,000 (lb/ton) / 2.20462 (lb/kg)

3. Proposed Project Increase in Power Output (MW) is based on the ratio of Natural Gas to Fuel Oil Heat Input Capacity, which is then applied to -the output (MW) for all four generators to estimate project increases. kW = MW * 1,000 kW/MW. Theoretical estimate based on heat input difference between gas and fuel oil.

4. David, Jeremy and Howard Herzog, The Cost of Carbon Capture, published 2000, p. 2, accessed at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.195.9269&rep=rep1&type=pdf

5. Energy Used for Capture (kWh/yr) = Energy Used for Capture (kWh/kg CO_2 processed) * CO_2 Captured (kg/yr)

6. Power Used for Capture (MW) = Energy Used for Capture (MWh/yr) / 3.500 (hr/yr). Hours represents sum of 3,000 hour for natural gas combustion and 500 hours for fuel oil combustion.

Table D-7. Assumptions Used in CCS Cost Estimation for Turbines[1]

Parameters	Value	Unit
Pipeline Length[2]	246	mi
Pipeline Diameter[3,4,5]	21	in
Average Storage Site Depth[6]	287	m
	940	ft
Number of Injection Wells[7]	2	
Uncontrolled Annual Natural Gas CO_2 Emissions[8]	1,239,479	tpy
Uncontrolled Maximum Natural Gas Daily CO_2 Emissions[8]	9,916	tpd
Uncontrolled Annual Fuel Oil CO_2 Emissions[8]	308,169	tpy
Uncontrolled Maximum Daily Fuel Oil CO_2 Emissions[8]	14,792	tpd
Control Efficiency[9]	90%	
Annual Captured CO_2 Emissions	1,392,882	tpy
Daily Maximum Captured CO_2 Emissions	13,313	tpd
Post-Project Net Power Output without CCS	728	MW
Post-Project Net Power Output with CCS[10]	600	MW

Gas because there are limited available resources to adapt these figures to natural gas pipeline connections to simple cycle turbines.

2. Distance from the facility to the nearest potential CO_2 sequestration facility (Black Warrior Basin) per the Southeast Regional Carbon Sequestration Partnership (SECARB), conservatively assuming the shortest distance as the pipeline route. Note that this site utilized an injection well as part of SECARB's Phase I study, but that injection well has reverted back to its original use for coalbed methane production.
http://secarbon.org/index.php?page_id=8 and http://secarbon.org/files/black-warrior-basin.pdf

3. Estimating Carbon Dioxide Transport and Storage Costs, National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447 (March 2010), Figure 3. The required diameter for a 246 mile long pipeline is 18 inches at 10,000 tons/day CO_2.
http://www.canadiancleanpowercoalition.com/pdf/CTS11%20-%20QGESStransport.pdf

4. The required diameter is conservatively estimated by scaling 18 inches of diameter (necessary for a 10,000 tons/day CO_2 flowrate) by the square root of the ratio of the flowrates.
18 inches * (Daily Maximum Captured CO_2 Emissions /10,000)$^{1/2}$ = Necessary diameter in inches.
See the 1-D inlets & outlets (for incompressible flow) section of
https://www.mne.psu.edu/cimbala/Learning/Fluid/CV_Mass/home.htm for reference.

5. *Carbon Dioxide Transport and Storage Costs in NETL Studies*, National Energy Technology laboratory, U.S. DOE, DOE/NETL-2017/1819 (November 2017), Exhibit 2-2. The calculated diameter for a 246 mile long pipeline is 21 inches at 10,000 tons/day CO_2. Since a 21 inch pipeline would not be available for installation, a 20 inch size was selected.
https://www.netl.doe.gov/projects/files/QGESSCarbonDioxideTransportandStorageCostsinNETLStudies_110617.pdf

6. The shallowest injection depth at Black Warrior Basin is 940 feet or 286.51 meters. Shallowest depth is used for conservatism. http://secarbon.org/index.php?page_id=8

7. Each injection well can only accommodate an average of 10,320 tons/day based on the document in reference 2.

8. Emissions calculated in Table D-1.

9. 90% CCS Control Efficiency from https://sequestration.mit.edu/pdf/David_and_Herzog.pdf

10. Net Power Output with CCS = Power Output After Project (without CCS) - Power Used for Capture if CCS included (MW)

Table D-8. Capital and O&M Costs of Carbon Capture

			December 2018 Dollars		November 2020 Dollars[2]
Capture Capital Costs for CCCTs [1,2]		$	622,642,559	$	644,937,769
	Total Capital	$	622,642,559	$	644,937,769
O&M					
Fixed Operating Costs[2,4]	Labor, Property Taxes, Insurance	$	18,845,106	$	19,519,900.25
Variable Operating Costs[2,5]	Water, Chemicals (MEA Solvent)		--	$	7,468,713
	Total O&M	$	18,845,106	$	26,988,613

1. Based on the September 2019 DOE Report, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* the total capital cost difference between a natural gas CCCT energy facility with and without capture in terms of $/kW (net) is relied upon to estimate the capital costs associated with capture equipment. Exhibit 5-17, Case B31A Total Plant Cost Details (page 505) and Exhibit 5-31, Case B31B Total Plant Cost Details (page 524).

Capture Capital Costs for CCCTs = [Total Plant Capital Cost (capture) ($/kW) * Post-Project Net Power Output with CCS (kW)] - [Total Plant Capital Cost (no capture) ($/kW) * Post-Project Net Power Output without CCS Penalty (kW)]

Total Plant Capital Cost - No Capture	780	$/kW
Total Plant Capital Cost - With Capture	1984	$/kW

2. Costs were adjusted from specified dollars to the November 2020 dollars per the consumer price index for all items: https://www.bls.gov/data/

CPI for December 2018	251.233
CPI for November 2020	260.229

3. Note that the four turbines would share a carbon capture system; therefore additional cost is required for connecting the turbines to a single carbon capture system. WCP conservatively estimated there is no additional cost for connecting the turbines into a single pipeline for purposes of this estimate.

4. Based on the September 2019 DOE Report, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,* the total fixed operating cost difference between a natural gas CCCT energy facility with and without capture in terms of $/kW (net) is relied upon to estimate the fixed operating costs associated with capture equipment. Exhibit 5-19. Case B31A Initial and Annual Operating and Maintenance Costs (page 507) and Exhibit 5-33. Case B31B Initial and Annual Operating and Maintenance Costs (page 526).

Fixed Operating Costs = [Total Fixed Operating Cost (capture)($/kW) * Post-Project Net Power Output with CCS (kW)] - [Total Fixed Operating Cost (no capture) ($/kW) * Post-Project Net Power Output without CCS (kW)]

Total Fixed Operating Costs - No Capture	26.792	$/kW
Total Fixed Operating Costs - With Capture	63.911	$/kW

5. Based on the September 2019 DOE Report, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, the total variable operating cost difference between a natural gas CCCT energy facility with and without capture in terms of $/kWh (net) is relied upon to estimate the variable operating costs associated with capture equipment. Exhibit 5-19. Case B31A Initial and Annual Operating and Maintenance Costs (page 507) and Exhibit 5-33. Case B31B Initial and Annual Operating and Maintenance Costs (page 526). The Total Variable Operating Cost was re-evaluated below to remove the Ammonia and SCR Catalyst and serves as a conservative estimate to connect to a Simple Cycle Combustion Turbine. Annualized variable operating costs were calculated assuming the lowest possible hours of operation for the facility for the year, which are 3,000 hours/yr for Natural Gas and 500 hours/yr for Fuel Oil.

Variable Operating Costs = [Total Variable Operating Cost (capture)($/kWh) * Post-Project Net Power Output with CCS (kW)] - [Total Variable Operating

Maintenance Materials	*1.19E-03*	*$/kWh*
Water Cost	*2.28E-04*	*$/kWh*
Makeup and Waste Water Treatment Chemicals	*1.96E-04*	*$/kWh*
Total Variable Operating Costs - No Capture	1.62E-03	$/kWh
Maintenance Materials	*3.04E-03*	*$/kWh*
Water Cost	*4.21E-04*	*$/kWh*
Makeup and Waste Water Treatment Chemicals	*3.63E-04*	*$/kWh*
CO_2 Capture System Chemicals	*1.51E-03*	*$/kWh*
Triethylene Glycol Consumption	*1.73E-04*	*$/kWh*
Triethylene Glycol Waste Disposal	*8.89E-06*	*$/kWh*
Thermal Reclaimer Unit Waste	*1.33E-06*	*$/kWh*
Total Variable Operating Costs - With Capture	5.52E-03	$/kWh

Table D-9. Capital and O&M Costs of Pipeline Transportation

Capital Costs	**Factor**	**Unit**	**December 2011 Dollars**	**December 2018 Dollars**	**November 2020 Dollars[3]**
Pipeline Costs[1]					
Pipeline Cost	$ 1,700,000	$/mi for a 20 inch pipeline	--	$ 418,200,000	$ 433,174,654
		Total Capital	--	$ 418,200,000	$ 433,174,654
O&M[2]					
Fixed O&M	$ 8,454	$/mile/yr	$ 2,079,684	--	$ 2,398,145

1. Based on National Energy Technology Laboratory guidance, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL-2019/2044, Exhibit 2-3, August 2019, for a 20 inch pipeline using the Parker model. The pipeline cost was available for a 20 inch or a 24 inch pipeline diameter. Although Table D-3 above calculates the necessary pipeline diameter as 21 inches for maximum daily operations, a 20 inch pipeline diameter is conservatively chosen for the pipeline cost calculation.
2. Annual O&M costs per National Energy Technology Laboratory guidance, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL-2013/1614, Exhibit 2, March 2013.
3. Costs were adjusted from December 2011 and December 2018 dollars to the November 2020 dollars per the consumer price index for all items: https://www.bls.gov/data/

CPI for December 2011	225.672
CPI for December 2018	251.233
CPI for November 2020	260.229

Table D-10. Capital and O&M Costs of Geological Storage

Capital Costs[1]	**Factor**	**Unit**	**June 2007 Dollars**	**November 2020 Dollars[2]**
Site Screening and Evaluation		$	$ 4,738,488	########
Injection Wells	$240{,}714 \cdot e^{0.0008 \cdot \text{well-depth}}$	$/injection well, well-depth(m)	$ 605,447	$ 756,195
Injection Equipment	94,029*(7,389/(280*# of injection wells))^0.5	$/injection well	$ 683,110	$ 853,196
Liability Bond		$	$ 5,000,000	$ 6,244,936
		Total Capital	$ 11,027,045	$ 13,772,638
O&M[1]				
Pore Space Acquisition	0.334	$/short tons CO_2 captured	$ 465,223	$ 581,057
Normal Daily Expenses	11,566	$/injection well	$ 23,132	$ 28,892
Consumables	2,995	$/yr/short tons CO_2/day	$ 39,872,098	$ 49,799,743
Surface Maintenance	23,478*(7,389/(280*# of injection wells))^0.5	$/injection well	$ 85,282	$ 106,517
Subsurface Maintenance	7.08	$/ft depth/injection well	$ 13,310	$ 16,625
		Total O&M	$ 40,459,045	$ 50,532,833

1. "Estimating Carbon Dioxide Transport and Storage Costs," National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010. http://www.canadiancleanpowercoalition.com/pdf/CTS11%20-%20QGESStransport.pdf

2. Costs were adjusted from June 2007 dollars to the November 2020 dollars per the consumer price index for all items: https://www.bls.gov/data/

CPI for June 2007	208.352
CPI for November 2020	260.229

Table D-11. Overall Cost of CCS and Cost Effectiveness

				November 2020 Dollars
Total Capital Investment (TCI)[1]			$	1,091,885,061
Capital Recovery Factor (CRF)[2]	7% interest, 10 year lifespan	0.14		
Amortized Cost	CRF*TCI		$	155,459,868
Total O&M Cost			$	79,919,591
Total Annualized Cost	Amortized Cost + O&M Costs		$	235,379,459
Cost Effectiveness ($/ton)[3]			**$**	**168.99**

1. Total Capital Investment (TCI) is equal to the sum of capital costs for carbon capture, transportation, and storage.
2. Calculated using the formula from the EPA OAQPS Control Cost Manual.
3. Cost Effectiveness = Total Annualized Cost ($)/ CO_2 Emissions Captured (tons).

APPENDIX E. SIP PERMIT APPLICATION FORMS

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program
4244 International Parkway, Suite 120
Atlanta, Georgia 30354
404/363-7000
Fax: 404/363-7100

SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: ______________ Application No. ______________

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: Washington County Power

AIRS No. (if known): 04-13- 303 - 00039

Facility Location: Street: 1177 County Line Road

City: Sandersville Georgia Zip: 31082 County: Washington

Is this facility a "small business" as defined in the instructions? Yes: ☐ No: ☒

2. Facility Coordinates

Latitude: 33° 5 '21.5" **NORTH** Longitude: 82° 58' 51.5" **WEST**

UTM Coordinates: 315104.54 **EAST** 3662933.05 **NORTH** **ZONE** 17S

3. Facility Owner

Name of Owner: Washington County Power, LLC

Owner Address Street: 1177 County Line Road

City: Sandersville State: GA Zip: 31082

4. Permitting Contact and Mailing Address

Contact Person: Mike Spranger Title: Plant Manager

Telephone No.: 404-832-7571 Ext. ______ Fax No.: ______

Email Address: mikespranger@cogentrix.com

Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐

If Other: Street Address: 208 Cherry Hill Road

City: Monroe State: GA Zip: 30656

5. Authorized Official

Name: Mike Spranger Title: Plant Manager

Address of Official Street: 1177 County Line Road

City: Sandersville State: GA Zip: 31082

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: ______________________ Date: ______________

6. Reason for Application: (Check all that apply)

☐ New Facility (to be constructed)

☒ Existing Facility (initial or modification application)

☒ Permit to Construct

☒ Permit to Operate

☐ Change of Location

☐ Permit to Modify Existing Equipment: Affected Permit No.: ______

☐ Revision of Data Submitted in an Earlier Application

Application No.: ______

Date of Original Submittal: ______

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

☒ **No** ☐ **Yes, please fill out the SIP Exemption Attachment** (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

☐ **No** ☐ **Yes, SBAP** ☒ **Yes, a consultant has been employed or will be employed.**

If yes, please provide the following information:

Name of Consulting Company: Trinity Consultants

Name of Contact: Justin Fickas

Telephone No.: 678-441-9977, ext. 228 Fax No.: 678-441-9978

Email Address: jfickas@trinityconsultants.com

Mailing Address: Street: 3495 Piedmont Road, Building 10, Suite 905

City: Atlanta State: GA Zip: 30305

Describe the Consultant's Involvement:

Prepared potential to emit calculations, application narrative, and SIP forms

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
x	2.00 Emission Unit List
x	2.01 Boilers and Fuel Burning Equipment
x	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
x	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
x	4.00 Emissions Data
	5.00 Monitoring Information
s	6.00 Fugitive Emission Sources
x	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: Late 2021

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☒ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	**Actual (tpy)**
Carbon monoxide (CO)	N/A	N/A
Nitrogen oxides (NOx)	N/A	N/A
Particulate Matter (PM) (filterable only)	N/A	N/A
PM <10 microns (PM10)	N/A	N/A
PM <2.5 microns (PM2.5)	N/A	N/A
Sulfur dioxide (SO_2)	N/A	N/A
Volatile Organic Compounds (VOC)	N/A	N/A
Greenhouse Gases (GHGs) (in CO2e)	N/A	N/A
Total Hazardous Air Pollutants (HAPs)	N/A	N/A
Individual HAPs Listed Below:		
	N/A	N/A

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	**Actual (tpy)**	**Potential (tpy)**	**Actual (tpy)**
Carbon monoxide (CO)	99.53	N/A	291.77	N/A
Nitrogen oxides (NOx)	249	N/A	624.48	N/A
Particulate Matter (PM) (filterable only)	N/A	N/A	109.10	N/A
PM <10 microns (PM10)	63.71	N/A	173.01	N/A
PM <2.5 microns (PM2.5)	63.71	N/A	173.01	N/A
Sulfur dioxide (SO_2)	79.6	N/A	9.64	N/A
Volatile Organic Compounds (VOC)	9.83	N/A	103.99	N/A
Greenhouse Gases (GHGs) (in CO2e)	N/A	N/A	1,560,525	N/A
Total Hazardous Air Pollutants (HAPs)	3.46	N/A	13.91	N/A
Individual HAPs Listed Below:				
Formaldehyde	N/A	N/A	8.06	N/A
Toluene	N/A	N/A	1.39	N/A
Xylenes	N/A	N/A	0.72	N/A

Acetaldehyde	N/A	N/A	0.42	N/A
Ethylbenzene	N/A	N/A	0.34	N/A
Propylene Oxide	N/A	N/A	0.31	N/A

14. 4-Digit Facility Identification Code:

SIC Code: 4911 SIC Description: Electric Services

NAICS Code: 49119902 NAICS Description: Generation, electric power

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

This facility is currently authorized to operate five simple cycle combustion turbines, each capable of generating 169 MW of electricity. However, only four combustion turbines have been built. Each combustion turbine can only burn natural gas. A permit is being requested to retrofit the turbines to add the capacity to also fire fuel oil.

16. Additional information provided in attachments as listed below:

Attachment A - Area Map and Process Flow Diagram
Attachment B - Emission Calculations
Attachment C - RBLC Search Results
Attachment D - Control Cost Analyses
Attachment E - SIP Permit Application Forms
Attachment F -

17. Additional Information: Unless previously submitted, include the following two items:

☒ Plot plan/map of facility location or date of previous submittal:

☒ Flow Diagram or date of previous submittal:

18. Other Environmental Permitting Needs:

Will this facility/modification trigger the need for environmental permits/approvals (other than air) such as Hazardous Waste Generation, Solid Waste Handling, Water withdrawal, water discharge, SWPPP, mining, landfill, etc.?

☒ **No** ☐ **Yes, please list below:**

19. List requested permit limits including synthetic minor (SM) limits.

20. Effective March 1, 2019, permit application fees will be assessed. The fee amount varies based on type of permit application. Application acknowledgement emails will be sent to the current registered fee contact in the GECO system. If fee contacts have changed, please list that below:

Fee Contact name: Mike Spranger

Fee Contact email address: mikespranger@cogentrix.com

Fee Contact phone number: 404-832-7571

Fee invoices will be created through the GECO system shortly after the application is received. It is the applicant's responsibility to access the facility GECO account, generate the fee invoice, and submit payment within 10 days after notification.

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
T1	Combustion Turbine 1	General Electric 7FA	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 170MW.
T2	Combustion Turbine 2	General Electric 7FA	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 170MW.
T3	Combustion Turbine 3	General Electric 7FA	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 170MW.
T4	Combustion Turbine 4	General Electric 7FA	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 170MW.
ST	Fuel Oil Storage Tank	TBD	2.5 million gallon vertical fixed-roof storage tank. Est throughput of 30 million gallons per year.

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

Emission Unit ID	Type of Burner	Type of Draft[1]	Design Capacity of Unit (MMBtu/hr Input)	Percent Excess Air	Dates		Date & Description of Last Modification
					Construction	Installation	
T1	Dry-Low NOx Burner	N/A	1766 for NG, 1890 for FO	N/A	TBD/2021	TBD/2021	Modified TBD/2021 for fuel oil capacity
T2	Dry-Low NOx Burner	N/A	1766 for NG, 1890 for FO	N/A	TBD/2021	TBD/2021	Modified TBD/2021 for fuel oil capacity
T3	Dry-Low NOx Burner	N/A	1766 for NG, 1890 for FO	N/A	TBD/2021	TBD/2021	Modified TBD/2021 for fuel oil capacity
T4	Dry-Low NOx Burner	N/A	1766 for NG, 1890 for FO	N/A	TBD/2021	TBD/2021	Modified TBD/2021 for fuel oil capacity

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Washington County Power **Date of Application:** February 2021

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season									
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30	Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
T1	Natural Gas	5,194	MMscf/yr	N/A	N/A	1.73 MMscf/hr	N/A	N/A	1766 MMBtu/hr	<0.001	N/A	N/A	N/A
T1	Fuel Oil	6,750	Mgal/yr	0	100	13.5 Mgal/hr	N/A	N/A	1890 MMBtu/hr	0.0015	N/A	N/A	N/A
T2	Natural Gas	5,194	MMscf/yr	N/A	N/A	1.73 MMscf/hr	N/A	N/A	1766 MMBtu/hr	<0.001	N/A	N/A	N/A
T2	Fuel Oil	6,750	Mgal/yr	0	100	13.5 Mgal/hr	N/A	N/A	1890 MMBtu/hr	0.0015	N/A	N/A	N/A
T3	Natural Gas	5,194	MMscf/yr	N/A	N/A	1.73 MMscf/hr	N/A	N/A	1766 MMBtu/hr	<0.001	N/A	N/A	N/A
T3	Fuel Oil	6,750	Mgal/yr	0	100	13.5 Mgal/hr	N/A	N/A	1890 MMBtu/hr	0.0015	N/A	N/A	N/A
T4	Natural Gas	5,194	MMscf/yr	N/A	N/A	1.73 MMscf/hr	N/A	N/A	1766 MMBtu/hr	<0.001	N/A	N/A	N/A
T4	Fuel Oil	6,750	Mgal/yr	0	100	13.5 Mgal/hr	N/A	N/A	1890 MMBtu/hr	0.0015	N/A	N/A	N/A

Fuel Supplier Information						
Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Natural Gas	GA Power	(855) 936-7438	Black Warrior Basin Pipeline	N/A	AL/GA	N/A
Fuel Oil	TBD	TBD	TBD	TBD	TBD	TBD

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 2.02 – ORGANIC COMPOUND STORAGE TANK

Emission Unit ID	Emission Unit Name	Capacity (gal)	Material Stored	Maximum True Vapor Pressure (psi @ ºF)	Storage Temp. (ºF)	Filling Method	Construction/ Modification Date	Roof Type	Seal Type
ST	Fuel Oil Storage Tank	2,500,000	Diesel	0.004 psia	Ambient	TBD	**TBD/2021**	Fixed	N/A

Facility Name: Washington County Power **Date of Application:** February 2021

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

APCD Unit ID	Emission Unit ID	APCD Type (Baghouse, ESP, Scrubber etc)	Date Installed	Make & Model Number (Attach Mfg. Specifications & Literature)	Unit Modified from Mfg Specifications?	Gas Temp. °F		Inlet Gas Flow Rate (acfm)
						Inlet	Outlet	
WI1	T1	Water Injection	TBD/2021	TBD	N/A	1,113	TBD	717
WI1	T2	Water Injection	TBD/2021	TBD	N/A	1,113	TBD	717
WI1	T3	Water Injection	TBD/2021	TBD	N/A	1,113	TBD	717
WI1	T4	Water Injection	TBD/2021	TBD	N/A	1,113	TBD	717
LNB1	T1	Low NOx Burner	TBD/2021	N/A	N/A	N/A	1,113	N/A
LNB2	T2	Low NOx Burner	TBD/2021	N/A	N/A	N/A	1,113	N/A
LNB3	T3	Low NOx Burner	TBD/2021	N/A	N/A	N/A	1,113	N/A
LNB4	T4	Low NOx Burner	TBD/2021	N/A	N/A	N/A	1,113	N/A

Facility Name: Washington County Power **Date of Application:** February 2021

Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
WI1	NOx	50%	N/A	TBD	Calculated	TBD	TBD	N/A
WI2	NOx	50%	N/A	TBD	Calculated	TBD	TBD	N/A
WI3	NOx	50%	N/A	TBD	Calculated	TBD	TBD	N/A
WI4	NOx	50%	N/A	TBD	Calculated	TBD	TBD	N/A
LNB1	NOx	50%	NOx	N/A	Calculated	N/A	N/A	N/A
LNB2	NOx	50%	NOx	N/A	Calculated	N/A	N/A	N/A
LNB3	NOx	50%	NOx	N/A	Calculated	N/A	N/A	N/A
LNB4	NOx	50%	NOx	N/A	Calculated	N/A	N/A	N/A

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
T1-T4	W1	T1-T4	CO	N/A	435.07	N/A	283.44	Emission Factors
T1-T4	W1	T1-T4	NOx	N/A	1,268.04	N/A	610.94	Emission Factors
T1-T4	W1	T1-T4	Total PM	N/A	204.13	N/A	172.00	Emission Factors
T1-T4	W1	T1-T4	Total PM10	N/A	204.13	N/A	172.00	Emission Factors
T1-T4	W1	T1-T4	Total PM2.5	N/A	204.13	N/A	172.00	Emission Factors
T1-T4	W1	T1-T4	SO2	N/A	15.58	N/A	9.19	Emission Factors
T1-T4	W1	T1-T4	VOC	N/A	165.24	N/A	102.45	Emission Factors
T1-T4	W1	T1-T4	CO2e	N/A	2,064,077	N/A	1,549,985	Emission Factors
T1-T4	W1	T1-T4	Total HAP	N/A	5.16	N/A	13.32	Emission Factors
H1-H2	N/A	H1-H2	CO	N/A	1.66	N/A	7.29	Emission Factors
H1-H2	N/A	H1-H2	NOx	N/A	1.98	N/A	8.67	Emission Factors
H1-H2	N/A	H1-H2	Total PM	N/A	3.76E-02	N/A	0.16	Emission Factors
H1-H2	N/A	H1-H2	Total PM10	N/A	0.15	N/A	0.66	Emission Factors
H1-H2	N/A	H1-H2	Total PM2.5	N/A	0.15	N/A	0.66	Emission Factors
H1-H2	N/A	H1-H2	SO2	N/A	2.83E-02	N/A	0.12	Emission Factors
H1-H2	N/A	H1-H2	VOC	N/A	0.11	N/A	0.48	Emission Factors
H1-H2	N/A	H1-H2	CO2e	N/A	2,365	N/A	10,360	Emission Factors
H1-H2	N/A	H1-H2	Total HAP	N/A	0.12	N/A	0.53	Emission Factors
ST1	N/A	ST1	VOC Total HAP	N/A	0.15 0.17	N/A	0.66 5.89E-02	Emission Factors

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
T1	T1	90	18.50	Vertical	40	23.4	160	1,113	N/A	717
T2	T2	90	18.50	Vertical	40	23.4	160	1,113	N/A	717
T3	T3	90	18.50	Vertical	40	23.4	160	1,113	N/A	717
T4	T4	90	18.50	Vertical	40	23.4	160	1,113	N/A	717
H1	H1	15	1.30	Vertical	40	23.4	16	780	N/A	0.354
H2	H1	15	1.30	Vertical	40	23.4	16	780	N/A	0.354
TANK	ST1	48	N/A	Vertical	40	23.4	N/A	Ambient	N/A	N/A

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

The Storage Tank was modeled via TankESP, see the Emission Calculation Data in Appendix B for this data.

Facility Name: Washington County Power **Date of Application:** February 2021

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
N/A	N/A	N/A	N/A	☐
				☐
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PSD PERMIT APPLICATION
Volume II – Modeling Report

Fuel Oil Conversion Project

Washington County Power, LLC

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1. EXECUTIVE SUMMARY

Washington County Power, LLC ("WCP") owns and operates a natural gas-fired simple-cycle power generation facility northwest of Sandersville, Georgia (the "Facility"). The Facility consists of four General Electric (GE) Frame 7A combustion turbines, with the capacity to generate approximately 680 MW, along with other ancillary facility equipment including two fuel gas heaters, an emergency fire pump engine, and an auxiliary generator engine. This facility currently operates under Permit No. 4911-303-0039-V-08-0, issued January 11, 2021.

The facility is proposing to modify the four existing simple-cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil.

The proposed project will require a Prevention of Significant Deterioration (PSD) permit as a major modification to an existing major source.[1] Projected-related emissions increases are anticipated to exceed the PSD significant emission rate (SER) thresholds for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).[2]

The application package contains the necessary state air construction and operating permit application for the proposed project, included in two (2) separate application volumes. This Volume II of the application package includes all the required air quality assessments necessary as part of this PSD permit application. Volume I of the application details the required emissions analyses, regulatory review, and control technology analyses.

1.1 Proposed Project Description

WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hours per year (hr/yr) and fuel oil combustion to 2,000 hr/yr.[3] More detail regarding the proposed project is provided in Section 2 of the Volume I of the application.

1.2 Permitting and Regulatory Requirements

WCP is submitting this construction and operating permit application, in accordance with the PSD permitting requirements, to request authorization to modify and operate the site's simple-cycle combustion turbines. Since WCP is a major source under the PSD permitting program, emission increases from the proposed

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[1] The Facility is currently a PSD minor source, with PSD avoidance limitations (e.g. Permit Condition No. 2.1.1) limiting facility wide emissions of NO_X to less than 250 tpy. The facility is not classified as one of the 28 named source categories, and is subject to a 250 tpy PSD major source threshold.

[2] CO_2e is carbon dioxide equivalents calculated as the sum of the six well-mixed GHGs (CO2, CH4, N2O, HFCs, PFCs, and SF6) with applicable global warming potentials per 40 CFR 98 applied.

[3] Proposed limits based on 3,000 hr/yr natural gas firing per turbine and 500 hr/yr fuel oil combustion per turbine.

project must be evaluated and compared to the SER thresholds for regulated pollutants under the PSD program. WCP has evaluated emissions increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, CO_2e, sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and VOC resulting from the proposed project for comparison to their respective PSD SER to determine whether PSD permitting is required, as shown in Table 1-1.[4]

Table 1-1. Proposed Project Emissions Increases

Pollutant	Project Emissions Increases (tpy)	PSD Significant Emission Rate (tpy)	PSD Triggered? (Yes/No)
Filterable PM	97.11	25	Yes
Total PM_{10}	154.76	15	Yes
Total $PM_{2.5}$	154.76	10	Yes
SO_2	8.86	40	No
NO_X	565.97	40	Yes
VOC	95.21	40	Yes
CO	264.21	100	Yes
CO_2e	1,402,932	75,000	Yes
Lead	0.03	0.60	No
Sulfuric Acid Mist	4.50	7.00	No

Since the combined project emissions increases of filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e exceed their respective SERs, the proposed project is required to undergo PSD review for each of those pollutants. Emission calculations are described in Section 3 of the Volume I of the application, and PSD permitting requirements are detailed in Section 4.1 of the Volume I of the application.

WCP is submitting this construction and operating permit application package in accordance with all federal and state requirements. The proposed project will be subject to federal New Source Performance Standards (NSPS) and the Georgia Rules for Air Quality Control (GRAQC). Applicability of these programs is discussed in Section 4 of the Volume I of the application.

1.3 Modeling Summary

The results of the air quality dispersion modeling analyses presented in this report are summarized as follows:

- Ambient PM_{10} impacts from the project in the form of the standard are below the Class I and Class II Significant Impact Levels (SILs) for all applicable averaging periods.
- Ambient $PM_{2.5}$ impacts from the project in the form of the standard are below the Class I SILs for all applicable averaging periods. Ambient $PM_{2.5}$ impacts for the project in the form of the standard are above the Class II SIL for the 24-hr averaging period and annual averaging period. Subsequent modeling

[4] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, lists the lead (Pb) emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed project were not evaluated.

demonstrated that WCP's operations do not cause or contribute to any violation of the $PM_{2.5}$ NAAQS or Class II PSD Increment standard.
- Ambient NO_2 impacts from the project in the form of the standard are below the Class I SILs for for the annual averaging period. Ambient NO_2 impacts for the project in the form of the standard are above the Class II SIL for the 1-hr averaging period and annual averaging period. Subsequent modeling demonstrated that WCP's operations do not cause or contribute to any violation of the NO_2 NAAQS or Class II PSD Increment standard.
- An evaluation of plume blight, using the VISCREEN model, showed no issues with visibility based impacts for the Class II visibility areas of concern near the facility.
- Toxic Air Pollutant (TAP) modeled impacts are below applicable ambient air quality thresholds of concern.

The PSD air quality analyses described in this report demonstrates that the proposed project will neither cause nor contribute to a violation of any NAAQS and/or PSD Increment for PM_{10}, $PM_{2.5}$, CO or NO_2.

1.4 Application Contents

Volume II of this permit application is organized as follows:

- Section 2 contains a description of the facility and proposed project;
- Section 3 describes the PSD modeling procedures;
- Section 4 discusses the technical approach employed in the modeling analyses;
- Section 5 describes the results of the PSD dispersion analyses;
- Appendix A includes an area map, site layout map, and other supporting figures;
- Appendix B includes the Class I notification letter and Federal Land Manager (FLM);
- Appendix C includes the modeling protocol and Georgia Environmental Protection Division (EPD) response;
- Appendix D includes the emissions information used in modeling; and
- Appendix E contains electronic modeling files.

2. PROPOSED PROJECT DESCRIPTION

2.1 Facility Description

Figure 2-1 provides a map of the area surrounding the existing proposed project location. The approximate central Universal Transverse Mercator (UTM) coordinates of the Facility (centered around the emissions sources) are 315.183 kilometers (km) East and 3,663.253 km North in Zone 17 (NAD 83). The area surrounding the facility is predominantly rural.

Figure 2-1. Facility Location

Figure 2-2 depicts the fence line boundary of the Facility. The boundary area indicated in the figure is completely fenced.

Figure 2-2. Facility Boundaries

2.2 Description of Proposed Project

WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hours per year (hr/yr) and fuel oil combustion to 2,000 hr/yr. The proposed fuel oil storage capacity on-site could be as much as a 2.5 million gallon vertical fixed-roof storage tank, with a conservatively estimated fuel oil throughput of 30 million gallons per year. WCP proposes to continue operating the existing Dry Low NO_X burners on the turbines during gas combustion and proposes to install and operate a water-injection system during fuel oil combustion.

As the units are large-frame simple-cycle units, startup and shutdown operations will generally be limited to less than 30 minutes for both gas and oil operations. Therefore, worst-case hourly conditions for these turbines is generally considered to be a full hour at 100% operating load (steady-state). During gas combustion at 100% operating load, the estimated heat input capacity is estimated to be 1,766 Million British Thermal Units per hour (MMBtu/hr) for each turbine, whereas during fuel oil combustion at 100% operating load, the heat input capacity is estimated to be 1,890 MMBtu/hr for each turbine. Collectively, the four turbines will continue to maintain a 680-MW capacity for the site. WCP does not plan to expand overall short-term generating capacity. However, the annual generation (MW-hr) may increase due to both the addition of fuel oil operating capacity and additional run-time capacity on natural gas. This project would also require WCP to add pump skids, tanks, and a raw water storage tank for the purposes of water injection control but should not require the addition or modification of any other emission units on-site.

WCP proposes to begin making investments (i.e., purchasing equipment) as early as September 2021, and proposes to be operational by the end of 2022. Therefore, WCP is submitting this application into EPD's Expedited Permitting Program to ensure that a final permit is obtained by September 2021.

3. PSD MODELING REQUIREMENTS

The following sections detail the methods and models used to demonstrate that the proposed project will not cause or contribute to a violation of either the NAAQS or the PSD Class I or Class II Increment. The dispersion modeling analyses were conducted in accordance with the following guidance documents, as well as the approved modeling protocol[5]:

- *Guideline on Air Quality Models* 40 CFR 51, Appendix W (EPA, Revised, January 17, 2017)
- User's Guide for the AMS/EPA Regulatory Model – AERMOD, (EPA, August 2019)
- AERMOD Implementation Guide (EPA, August 2019)
- New Source Review Workshop Manual (EPA, Draft, October 1990)
- Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS (EPA, Memorandum from Mr. Stephen Page, March 23, 2010)
- Draft Guidance for Ozone and Fine Particulate Matter Modeling (EPA, Memorandum from Mr. Richard A. Wayland, February 10, 2020)
- Revised Policy on Exclusions from "Ambient Air" (EPA, Memorandum from Mr. Andrew R. Wheeler, December 2, 2019)
- PSD Permit Application Guidance Document (Georgia EPD, Draft, February 2017)
- *Guidance for $PM_{2.5}$ Permit Modeling* (EPA, Memorandum from Mr. Stephen Page, May 20, 2014)
- Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia (Georgia EPD, February 25, 2019)
- 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 (EPA, Memorandum from Mr. Richard A Wayland, December 2, 2016) and associated errata document (February 2017)
- Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program (EPA, Memorandum from Mr. Richard A Wayland, April 30, 2019)
- Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (EPA, Memorandum from Mr. Peter Tsirigotis, April 17, 2018)
- Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (EPA, Memorandum from Mr. Tyler Fox, March 1, 2011)
- Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard (EPA, Memorandum from Mr. R. Chris Owen and Roger Brode, September 30, 2014); and
- Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Georgia EPD, Revised, May 2017)

Part C of Title I of the Clean Air Act, 42 U.S.C. §§7470-7492, is the statutory basis for the PSD program. The U.S. EPA has codified PSD definitions, applicability, and requirements in 40 CFR Part 52.21. PSD is the component of the federal New Source Review (NSR) permitting program that is applicable in areas that are not designated as in nonattainment of the NAAQS. Washington County, where the facility is located, is currently designated as "attainment" or "unclassifiable" for all criteria pollutants.[6]

[5] Modeling protocol submitted to the Georgia EPD on October 29, 2020, with comments received from the Georgia EPD on November 25, 2020. Copies of these documents can be found in Appendix C.

[6] 40 CFR 81.311

The proposed project at the Facility will be considered a major modification under PSD since the proposed project emissions increases for certain criteria pollutants and GHGs are expected to exceed their respective PSD SERs.

As discussed in Volume I and shown in Table 1-1, the project emission rates trigger PSD permitting for multiple criteria pollutants with established SILs, NAAQS, and/or PSD Increment standards, specifically CO, NO_2, PM_{10}, and $PM_{2.5}$. VOC/NOx ozone based impacts are assessed in evaluation of the MERPs.

This section addresses requirements for evaluating NAAQS, PSD Increment, Class I Area, and additional impacts.

3.1 Class II Significance Analysis

The Class II Significance Analysis is conducted to determine whether the emissions increases associated with the project would cause a significant impact upon the area surrounding the facility. The Significance Analysis applies to CO, NO_2, PM_{10} and $PM_{2.5}$, as these are the pollutants for which PSD modeling requirements are triggered. “Significant” impacts are defined by ambient concentration thresholds commonly referred to as the SILs, shown in Table 3-1.

Table 3-1. Significant Impact Levels, NAAQS, PSD Class II Increments, and Monitoring de Minimis Levels for Criteria Air Pollutants

Pollutant	Averaging Period	Class II SIL (µg/m³)	Primary NAAQS (µg/m³)	Class II PSD Increment (µg/m³)	Significant Monitoring Concentration (µg/m³)
CO	1-hour	2,000	40,000 (a)	--	--
	8-hour	500	10,000 (a)	--	575
NO_2	1-hour	7.5	188 (b)	--	--
	Annual	1	100 (c)	25(c)	14
PM_{10}	24-hour	5	150 (d)	30(a)	10
	Annual	1	--	17(c)	--
$PM_{2.5}$	24-hour	1.2 (e)	35 (b)(g)	9 (f)(a)	-- (e)
	Annual	0.2 (e)	12 (h)	4 (f)(c)	--

(a) Highest second high modeled output

(b) The 3-year average of the 98th percentile of the daily maximum 1-hr average (highest eighth high modeled output).

(c) Annual arithmetic average (highest first high modeled output).

(d) Not to be exceeded more than three times in 3 consecutive years (highest high second high, or highest sixth high modeled output).

(e) EPA promulgated $PM_{2.5}$ SILs, Significant Monitoring Concentrations (SMCs), and PSD Increments on October 20, 2010 [75 FR 64864, PSD for Particulate Matter Less Than 2.5 Micrometers Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Final Rule]. The SILs and SMCs became effective on December 20, 2010 (i.e., 60 days after the rule was published in the Federal Register) but the U.S. Court of Appeals decision on January 22, 2013 vacated the SMC and remanded the SIL values back to EPA for reconsideration. EPA has recently provided guidance (August 2016) and a finalized memo (April 2018) which recommended use of a 24-hr $PM_{2.5}$ SIL of 1.2 µg/m³, and an annual SIL of 0.2 µg/m³. However, the guidance indicated that the permitting authority had the discretion to continue to utilize the previously established annual SIL of 0.3 µg/m³. EPA responded to the vacatur of the SMCs by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements for $PM_{2.5}$.

(f) The above mentioned court decision did not impact the promulgated increment thresholds for $PM_{2.5}$.

(g) The 3-year average of the 98th percentile 24-hour average concentration (highest eighth high modeled output).

(h) The 3-year average of the annual arithmetic average concentration (highest first high modeled output).

The highest design concentrations out of all given modeling years for each pollutant-averaging time is compared to the SIL level shown in Table 3-1 to determine if the ambient air impact from the proposed project is significant. In the case of 24-hour and annual $PM_{2.5}$ evaluations, EPA guidance states that the applicant should determine the maximum concentration at each receptor per year, then average those values on a receptor-specific basis over the 5 years of meteorological data prior to comparing with the appropriate SIL.[7] However, this assessment is only appropriate for the $PM_{2.5}$ NAAQS, as the $PM_{2.5}$ Increment standard is not a statistical standard. Therefore, the maximum 5-year average values for $PM_{2.5}$ were compared to the applicable SILs to determine if a $PM_{2.5}$ NAAQS analysis is required, whereas the maximum year by year results for $PM_{2.5}$ were compared to the applicable SILs for a determination if a refined analysis for $PM_{2.5}$ Increment is required. For PM_{10}, the impacts were evaluated on a year by year basis for comparison to the SIL for both PSD Increment and the NAAQS.

As detailed further in Section 4.5.6, the Significance Analysis for $PM_{2.5}$ also considered secondary $PM_{2.5}$ impacts from the project NO_X and SO_2 emissions, in accordance with the February 2019 Georgia EPD MERPs guidance. Impact of secondary formation of ozone are also considered through the evaluation of the project VOC and NOx emissions, in accordance with the February 2019 Georgia EPD MERPs guidance.

For NO_2 NAAQS modeling, a concatenated meteorological data set to derive the appropriate form of the 1-hr NO_2 NAAQS standard was utilized. For annual NO_2 NAAQS modeling, each individual year was processed separately to evaluate maximum annual anticipated impacts.

For CO, the impacts were evaluated on a year by year basis for comparison to the SIL for the NAAQS.

When modeled design concentrations are less than the applicable SIL, further analyses (NAAQS and PSD Increment) are not required for that pollutant-averaging period.

If modeled impacts are greater than the SIL, a full NAAQS and PSD Increment analysis is required for that pollutant and averaging period to demonstrate that the facility neither causes nor contributes to any exceedances.

3.2 Ambient Background Data

The background concentrations were selected based on the most recent monitor data published by the Georgia EPD for the county of interest.[8] The chosen background values are shown in Table 3-2.

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[7] Please note that WCP did not use averaging for developing the PM2.5 SIL results for consideration of the PM2.5 Increment. Maximum annual values were used rather than 5-year average values.

[8] https://epd.georgia.gov/georgia-background-data - website indicates data last updated October 16, 2020.

Table 3-2. Selected Background Concentrations

PSD Pollutant	Averaging Period	2017-2019 Monitor Background Concentration (μg/m3)	Metric	Monitor Location
CO	1-hour	641	3-yr average of second-high	Statewide Value as Derived by EPD (Yorkville)
	8-hour	504		
NO_2	1-hour	30.3	3-yr average of 98th percentile	Statewide Value as Derived by EPD (Yorkville)
	Annual	4.5	3-yr arithmetic mean maximum	
PM_{10}	24-hour	30.0	3-yr average of fourth-high	Statewide Value as Derived by EPD (Fire Station #8)
$PM_{2.5}$	24-hour	18.4	3-yr average of 98th percentile	Sandersville
	Annual	7.9	3-yr arithmetic mean average	
Ozone	8-hour	0.064 ppmv	Annual 4th highest daily maximum 8-hr value, 3-yr average	Macon-Forestry Monitoring Site

3.3 Ambient Monitoring Requirements

The PSD Significance Analysis is also used to determine whether the applicant is exempt from ambient monitoring requirements. To determine whether pre-construction monitoring should be considered, the maximum modeled impacts attributable to the proposed project are assessed against Significant Monitoring Concentrations (SMC). The SMC for the applicable averaging periods for CO, NO_2, PM_{10} and $PM_{2.5}$ are provided in 40 CFR 52.21(i)(5)(i) and are listed in Table 3-1. A pre-construction air quality analysis using continuous monitoring data may be required for pollutants subject to PSD review per 40 CFR 52.21(m). If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the SMC, an applicant may be exempt from pre-construction ambient monitoring. The SMC value for $PM_{2.5}$ was vacated on January 22, 2013; however, EPA has responded to the vacatur by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements.

Georgia EPD maintains an extensive ambient monitoring system in Georgia and publishes available background data for $PM_{2.5}$ on its website. The Sandersville monitor is the selected ambient $PM_{2.5}$ monitor representative of ambient background concentrations of $PM_{2.5}$ in Washington County. The Sandersville monitor is located in Washington County, Georgia and is the closest ambient $PM_{2.5}$ monitor in Georgia to the Facility. Therefore, sufficient ambient background monitoring data is available for the region for $PM_{2.5}$.

3.4 Ozone Ambient Impact Analysis

Elevated ground-level ozone concentrations are the result of photochemical reactions among various chemical species. These reactions are more likely to occur under certain ambient conditions (e.g., high ground-level temperatures, light winds, and sunny conditions). The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). Pursuant to 40 CFR 52.21, ambient ozone monitoring is not required unless a project's emissions increase is greater than 100 tpy of VOC or NO_X.

EPA recently issued guidance specifying a SIL value for ozone of 1 ppb, and has developed a new demonstration methodology (the MERPs guidance) to provide a framework for a Tier 1 demonstration that can illustrate that a project will not cause or contribute to any violation of ambient ozone standards.[9] The February 2019 Georgia EPD guidance document titled *Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and* $PM_{2.5}$ *in Georgia*, which is based on the EPA MERPS guidance, was used to provide a Tier 1 demonstration that ozone impacts from the project will not cause or contribute to ambient air quality levels of ozone. Both VOC and NO_X emissions increases from the project were considered. Details regarding that analysis can be found in Section 4.5.6 of this report.

3.5 Class I Requirements

Class I areas are federally protected areas for which more stringent air quality standards apply to protect unique natural, cultural, recreational, and/or historic values. The following Class I areas are located within 300 km of the Facility (with the approximate distance to the facility listed)[10]:

- Okefenokee Wilderness (234 km)
- Cohutta Wilderness (244 km)
- Wolf Island Wilderness (247 km)
- Shining Rock Wilderness (248 km)
- Great Smoky Mountains (263 km)
- Joyce Kilmer-Slickrock Wilderness (264 km)

All other Class I areas are located at distances greater than 300 km from the Facility.

The FLMs have the authority to protect air quality related values (AQRVs) and to consider, in consultation with the permitting authority, whether a proposed major emitting facility or a proposed modification to an existing major emitting facility will have an adverse impact on such values. AQRVs for which PSD modeling is typically conducted include visibility and deposition of sulfur and nitrogen.

The ratio of emissions to Class I distance (i.e., Q/D) for this project for the Class I areas within 300 km was considered in order to determine if the FLM would require a full AQRV analysis. The FLM's AQRV Work Group (FLAG) 2010 guidance states that a Q/D value of ten or less indicates that AQRV analyses should not be required.[11]

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[9] *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program* (Memorandum from Mr. Richard A. Wayland, U.S. EPA, to Regional Air Division Directors, April 30, 2019).

[10] All distances approximate and based on data obtained from the Class I Area distance tool as published by the Florida Department of Environmental Protection (FL DEP) at https://floridadep.gov/air/air-business-planning/content/class-i-areas-map

[11] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service. 2010. Federal land managers' air quality related values work group (FLAG): phase I report, revised (2010). Natural Resource Report NPS/NRPC/NRR, 2010/232. National Park Service, Denver, Colorado.

Notifications were submitted to the appropriate FLMs for all Class I areas located more than 50 km from the Facility, and located within 300 km of the Facility, for concurrence with a finding regarding the requirement for AQRV analysis for this project.[12] The Q/D for all Class I areas located more than 50 km from the facility was evaluated and demonstrated that impacts are less than 10. Documentation regarding the Q/D analyses conducted, can be found in Appendix B.

A Significance Analysis was conducted for the Class I areas to determine if an evaluation of PSD Increment impacts upon the Class I area is required. AERMOD was utilized for all Significance Analyses. A screening procedure was utilized evaluating an array of receptors located 50 km from the facility at less than or equal to 1-degree intervals in the direction of the Class I areas of interest, to compare project emission increase impacts to those receptors at 50 km.[13] A 50 km-radius ring of receptors in the AERMOD model was developed. Significance results from those receptors also demonstrated that the Class I SILs for PM_{10}, $PM_{2.5}$, and NO_2 were not exceeded. Results of the analysis can be found in Section 5 of this report.

The Class I area SILs and PSD Increment thresholds utilized are listed below. $PM_{2.5}$ Class I SILs are taken from recent EPA guidance regarding appropriate recommended significant impact levels for $PM_{2.5}$.[14]

Table 3-3. Class I Significant Impact Levels and Increment Thresholds

Pollutant	Averaging Period	Class I SIL ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)
NO_2	Annual	0.1	2.5
$PM_{2.5}$	24-hour	0.27	2
	Annual	0.05	1
PM_{10}	24-hour	0.3	8
	Annual	0.2	4

3.6 Regional Inventory Data

As shown in Section 4 of this report, pollutants (and averaging periods) to exceed the Class II SILs were NO_2 for the 1-hr average and annual average, and $PM_{2.5}$ for the 24-hr average and annual average. No other pollutants (PM_{10} and CO) exceeded the Class II SILs.[15] No pollutants exceeded the Class I SILs, as referenced in Section 3.5 as shown in model results in Section 5.

As such, it was necessary to develop regional inventory data for Class II modeling of the 1-hr and annual NO_2 NAAQS, NO_2 annual increment, and 24-hr and annual $PM_{2.5}$ NAAQS/Increment. Per consultation with

[12] Copies of correspondence to date, are included in Appendix B. If EPD is not copied on any future correspondence from the FLM providing concurrence that no AQRV analysis is required, a copy of that correspondence will be provided to the Georgia EPD.

[13] Consistent with EPD guidance, this assumes that all applicable FLMs have determined that no AQRV analyses will be required for the project. Receptors start and end at approximately 10 degrees on either side of the azimuth to the Class I areas of interest, per EPD guidance.

[14] *Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program* (Memorandum from Mr. Peter Tsirigotis, U.S. EPA, to Regional Air Division Directors, April 17, 2018).

[15] Annual $PM_{2.5}$ exceeded the SIL for both NAAQS (concatenated 5-year data) and for PSD Increment (individual year data).

the Georgia EPD as part of the modeling protocol approval process, the regional inventory screening would be limited to an area within 50 km of the Facility. Modeling inventory information was compiled as follows:

3.6.1 Development of Initial Inventory Source List

Google Earth was relied upon to identify counties or part of the counties that are located within 50 km radius of the facility. As a result, fifteen (15) counties were identified, including Baldwin County, Glascock County, Greene County, Hancock County, Jefferson County, Johnson County, Jones County, Laurens County, McDuffie County, Putnam County, Taliaferro County, Twiggs County, Warren County, Washington County and Wilkinson County.

The Georgia EPD source list was queried and evaluated for all counties in Georgia within 50 km of the Facility.[16] Sources that are identified as not in operation were excluded. Sources that are classified as permit by rule category were excluded. This list serves as the basis of the initial inventory source.

The EPD PSD modeling inventory tool was queried for all source information within the counties of interest within 50 km of the Facility.[17] However, this resource only provides detailed source information for Title V and PSD major sources. This source list was compared against the Georgia EPD source list. There were no sources that were included in the PSD modeling inventory but not included in the Georgia EPD source list.

The EPD air permits website was queried (per county code) for the counties of interest within 50 km of the Facility for additional air permits issued since the EPD source list was last updated in June 2018.[18] The permit list was also reviewed for consistency with data provided in the June 2018 EPD permitted source listing. A few additional sources were added to the initial inventory source based on comparison of the permit list including Roche Manufacturing, Ballard Contractors and Hy-Lite Products Inc. Nichiha USA, Inc. located at Inside Plant Branch, Hwy. 441, Milledgeville, GA 31061 was removed as the site was demolished.

Based on the steps identified above, 79 sources were identified in the initial inventory source list as detailed in Table D-11 of Appendix D.

3.6.2 Development of Refined Inventory Source List

All resources were cross referenced to create an initial list of sources to consider for screening purposes via 20D. However, this initial listing was quite large (79 sources), inclusive of a significant number of minor sources. The initial inventory source list was reduced further by the following criteria:

- Review of online permit narrative information from some minor sources revealed that the sites of interest were not sources of NO_2 emissions or PM emissions. Therefore, those sites were also removed from consideration. For example, automotive body shop type facilities were excluded.
- Sources with no permit on EPD's website were excluded.
- If the street address and latitude/longitude coordinates from the June 2018 EPD permit list did not point to an industrial site, then the site was removed from consideration.

37 sources were identified as the refined inventory source list as detailed in Table D-23 of Appendix D. The refined list of inventory source was relied upon for screening purposes via 20D procedure as outlined in

[16] https://epd.georgia.gov/list-sources-georgia - last updated June 2018.

[17] https://psd.gaepd.org/inventory/

[18] https://permitsearch.gaepd.org/

Section 5.3.1 of the Georgia EPD PSD Guidance.[19] Specifically, all sites within 2 km of each were grouped together for consideration of total emissions. Potential emissions were obtained from the EPD PSD modeling inventory tool, permit narrative and the most recent Title V renewal applications as detailed in Table D-23 of Appendix D. If no data were found available, potential emissions were conservatively assumed based on the facility source status (minor source has PTE below Title V major source thresholds, so conservatively set emissions at 100 tpy). Calculations of cluster emission are detailed in Table D-24 of Appendix D. If the total emissions from the individual site (or group of sites) was less than 20 times the distance to the Facility, then the site was considered to be "screened out" and eliminated from the NAAQS/Increment modeling evaluation.[20] If the site was not "screened out," then it was further considered for use in the modeling inventory for the refined NO_2 NAAQS/Increment modeling and $PM_{2.5}$ NAAQS and PSD Increment modeling.[21]

20D review are detailed in Tables D-25 and D-26 in Appendix D.

3.6.3 File Review of Modeling Parameters

A file review at the Georgia EPD was conducted to review records both for the Title V/PSD major sources already identified (for validity of data from the PSD inventory tool) as well as for minor sources. 37 sources were identified for modeling following 20D screening for NO_2 and 9 sources were identified for modeling following 20D screening for $PM_{2.5}$. The file review excluded a few minor sources for modeling due to the following reasons;

- Permit documentation was available but indicated a lack of any usable information for dispersion modeling.
- File review indicated the site of interest was not a source of NO_2 emissions, and the source was, therefore, removed from consideration.

A listing of those sites identified, but not able to be modeled, is included in Appendix D, as well as the final major and minor source inventory information modeled for the NO_2 NAAQS and PSD Increment analysis and $PM_{2.5}$ NAAQS and PSD Increment analysis.

To alleviate difficultly in developing a specific $PM_{2.5}$ and NO_2 modeling inventory for assessment of $PM_{2.5}$ and NO_2 refined PSD Increment impacts, the $PM_{2.5}$ and NO_2 NAAQS inventory developed was conservatively used as the $PM_{2.5}$ and NO_2 Increment modeling inventory for the Class II Annual PSD Increment analysis. This is conservative since increment inventory sources are modeled at their $PM_{2.5}$ PTE, not specifically their increase or decrease in $PM_{2.5}$ emissions since the $PM_{2.5}$ baseline date, and should account for and offset any $PM_{2.5}$ secondary emission increases in the area since the 2010 trigger date for $PM_{2.5}$. As detailed in further sections, the secondary component of selected NO_2 inventory sources was conservatively chosen to evaluate secondary $PM_{2.5}$ impacts from baseline emissions increases from the regional area.

[19] *PSD Permit Application Guidance Document*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Draft, February, 2017.

[20] Taking the distance back to the site is appropriate in this instance, since the only pollutant and averaging period of concern for refined modeling is the 1-hr average NO_2 NAAQS, a short term averaging period. Any sources (for which information was available) within the SIA were modeled.

[21] There is no 1-hr average NO_2 PSD Increment standard. Therefore, the only refined modeling analysis included in this modeling report for 1-hr NO_2 is for the 1-hr average NO_2 NAAQS.

3.7 Additional Impacts Analysis

PSD regulations require that three additional impacts be considered as part of a PSD permit action: a soil and vegetation analysis, an economic growth analysis, and a visibility analysis. The effect of the proposed project's CO, NO_2, PM_{10} and $PM_{2.5}$ emissions increases on local soils and vegetation is addressed through comparison of modeled impacts to the secondary NAAQS and other relevant screening criteria that have been developed by the U.S. EPA to provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation and buildings.[22] The results of the soil and vegetation analysis are discussed in Section 5.5.

An economic growth analysis is intended to assess the amount of new growth that is likely to occur in support of the new project and to estimate emissions resulting from associated growth. Associated growth relates to any residential and commercial/industrial growth that may result from the proposed project. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. The proposed project will not result in a change of the current resources necessary to operate and support the project. Therefore, additional economic growth impacts from the proposed project will be minimal.

Visibility analyses for Class II areas are not necessary for proposed project that have no regional airports, state parks, or State Historic Sites located within the project's SIA. The proposed project's modeled impacts are under the SILs for PM_{10} and CO. The $PM_{2.5}$ SIA was limited to within 1 km of the facility. However, there are regional airports, state parks or State Historic Sites located within the project's 1-hr NO_2 SIA for fuel oil operation scenario of the turbines. Therefore, Class II visibility assessments were conducted for four of the nearest Class II visibility areas of concern.

While not a requirement under the federal PSD regulations, WCP has included an evaluation of toxic pollutant impacts for the facility emission sources as part of this permit application in accordance with Georgia EPD guidelines.[23] The post-project facility-wide potential emissions for each listed air toxic were compared to the Minimum Emission Rate (MER) values provided in guidance to determine if modeling for those air toxics was required. Toxic pollutant impacts are discussed in detail in Section 5.6.

Also, per 40 CFR 52.21, as the net emissions increase for the proposed project is greater than 100 tons per year of NO_X, an ambient air quality analysis or gathering of ambient air quality data is required for ozone. Additional consideration of ozone is discussed further in Section 4 of this report associated with the recent December 2016 EPA guidance document associated with Modeled Emission Rates for Precursors (MERPs), and Georgia EPD's state specific guidance regarding the MERPs (Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia, February 2019).

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[22] *U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA 450/2-81-078), 1980.

[23] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May, 2017.

4. MODEL SELECTION AND METHODOLOGY

This section includes a summary of the modeling methodology originally presented in the dispersion modeling protocol previously submitted to[24] and approved by[25] the Georgia EPD.

4.1 Selection of Model

Version 19191 of the AERMOD modeling system was used to estimate maximum ground-level concentrations in all air pollutant analyses conducted for this application. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and was promulgated in December 2005 as the preferred model for use by industrial sources for this type of air quality analysis.[26] The AERMOD model incorporates the Plume Rise Modeling Enhancements (PRIME), and the direction-specific building downwash dimensions used as inputs are determined by the Building Profile Input Program, PRIME (BPIP PRIME), version 04274.[27] BPIP PRIME is designed to incorporate the concepts and procedures expressed in the Good Engineering Practice (GEP) Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the PRIME enhancements to improve prediction of ambient impacts in building cavities and wake regions.[28]

The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the dispersion module. AERMAP is used to extract terrain elevations for selected model objects – emission points, buildings, and receptor points – and to generate the receptor hill heights that are used by AERMOD to drive advanced terrain processing algorithms. National Elevation Database (NED) data available from the U.S. Geological Survey (USGS) are utilized to interpolate surveyed elevations onto user-specified model objects in the absence of more accurate site-specific elevation data.

AERMET generates separate surface file and vertical profile file to pass meteorological observations and turbulence parameters to AERMOD. AERMET meteorological data are refined for a particular analysis based on the choice of micrometeorological parameters that are linked to the land use and land cover (LULC) around the particular facility and/or meteorological site. Complete sets of model-ready meteorological data specific are created by feeding raw surface and upper air station NWS observation data to AERMET. The details of the meteorological data used in the modeling evaluation for the proposed project are provided in Section 4.2.

An assessment of the appropriate land use category of the area surrounding the Facility was conducted. This assessment determined that use of the rural dispersion coefficients within the AERMOD model was appropriate for this analysis. Additional information is provided in Section 4.2.

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[24] Email from Mr. Justin Fickas (Trinity) to Mr. Byeong Kim (EPD), dated October 29, 2020. A copy of the modeling protocol can be found in Appendix C.

[25] Written approval provided in email correspondence from Mr. Byeong Kim (EPD) to Mr. Justin Fickas (Trinity) dated November 25, 2020. A copy of the modeling protocol response can be found in Appendix C.

[26] 40 CFR 51, Appendix W–Guideline on Air Quality Models, Appendix A.1– AMS/EPA Regulatory Model (AERMOD).

[27] Earth Tech, Inc., Addendum to the ISC3 User's Guide, The PRIME Plume Rise and Building Downwash Model, Concord, MA.

[28] U.S. EPA, Office of Air Quality Planning and Standards, Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised), Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

4.2 Meteorological Data and Land Use Representativeness

The U.S. EPA's federal *Guideline on Air Quality Models*, codified at 40 CFR 51, Appendix W, states in Section 9.3.1.2, "Meteorological Input Data – Recommendations":

> *... five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data may be collected either onsite or at the nearest National Weather Service (NWS) station.*

The meteorological data that are "representative" for a particular facility are typically determined subjectively, and the *Guideline* offers the following guidance in Section 9.3(a).

> *The meteorological data ... should be selected on the basis of spatial and climatological (temporal) representativeness as well as the ability of the individual parameters selected to characterize the transport and dispersion conditions in the area of concern. The representativeness of the data is dependent on: (1) the proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected. The spatial representativeness of the data can be adversely affected by large distances between the source and receptors of interest and the complex topographic characteristics of the area.*

The Facility is located in Washington County, Georgia. As outlined in the modeling protocol document (found in Appendix C), 2015-2019 meteorological data for the Middle Georgia Regional Airport surface station and the Peachtree City/Falcon Field upper air station, with the use of ADJ_U*, was selected for this modeling analysis. ADJ_U* is a regulatory default option that improves overall model performance during periods of low-wind/stable conditions by adjusting the surface frictional velocity (u*) in AERMET.

4.2.1 Representativeness Analysis

The Middle Georgia Regional Airport meteorological station is located at 32.6878 degrees (latitude) and -83.6544 degrees (longitude) and is approximately 78 km southwest of the Facility.

An AERSURFACE analysis was completed to compare the surface characteristics around the facility's location and the chosen meteorological NWS station. AERSURFACE was executed for both the facility site and the NWS station using monthly temporal resolution and the default 1 km radius domain of twelve 30-degree sectors for the roughness surface length.

Figure 4-1. Comparison of Land Use Categories around the Facility and the NWS Station

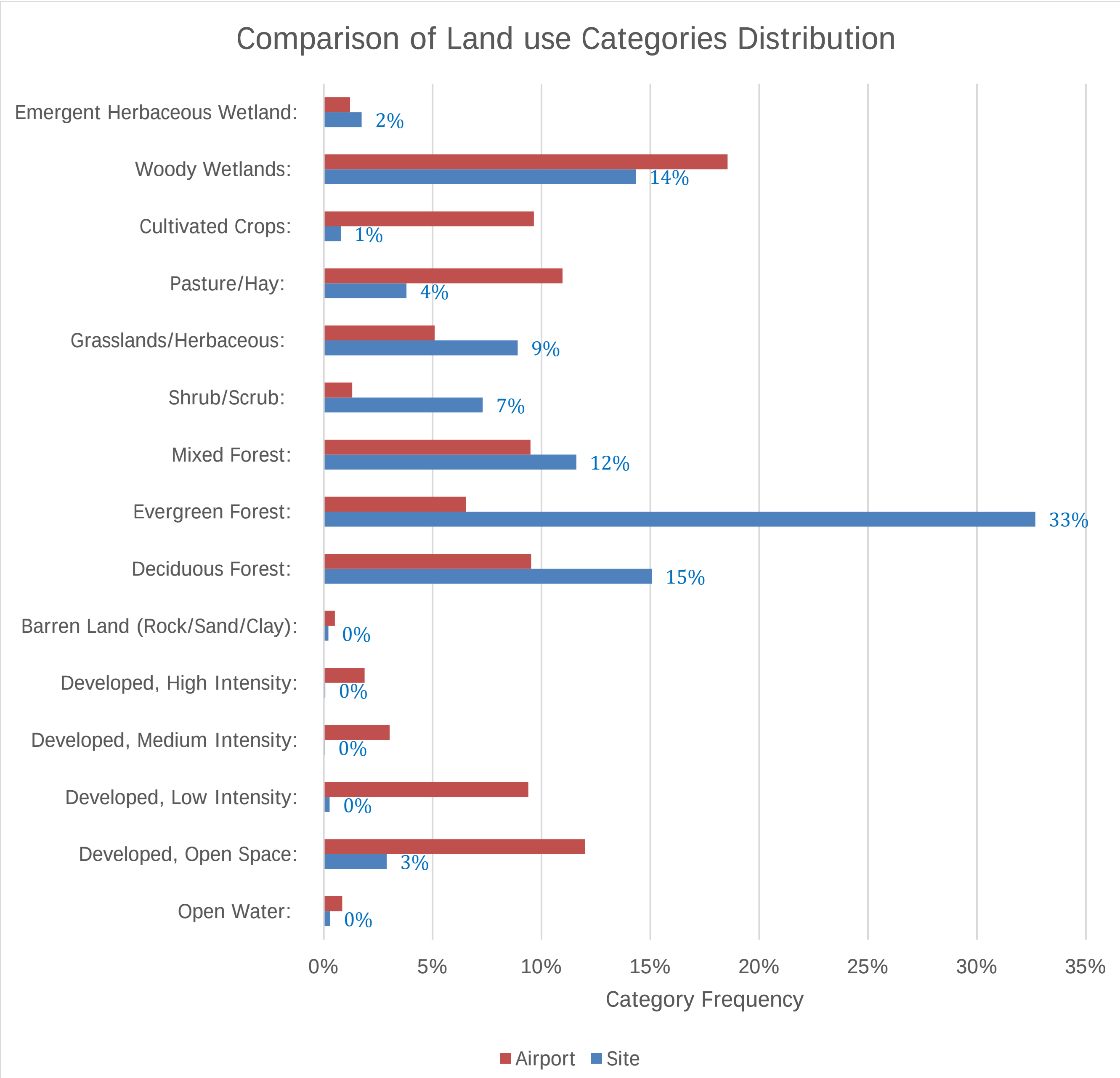

Figure 4-1 and Table 4-1 provide detailed comparison of the land use categories and surface parameters at the facility site and the NWS station. The albedo shows a maximum of 7% difference. The Bowen ratio shows differences ranging from 1 to 27%. The surface roughness is similar in most sectors, with a maximum difference of 92% for any sector. Although comparison values for some sectors differ significantly for surface roughness (as would be expected for an open area such as an airport and a developed facility), the Middle Georgia Regional Airport data is considered sufficiently representative for use for the modeling analysis.

Table 4-1. Comparison of Surface Characteristics between the Facility Site and NWS Locations

	Albedo								Albedo			
	Middle Georgia Regional Airport				Site				Difference (%): Site - Airport			
Sector	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)
Domain	0.16	0.15	0.16	0.16	0.15	0.14	0.15	0.15	-7%	-7%	-7%	-7%

	Bowen Ratio								Bowen Ratio			
	Middle Georgia Regional Airport				Site				Difference (%): Site - Airport			
Moisture Conditions	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)
Average	0.63	0.41	0.41	0.63	0.70	0.52	0.35	0.70	10%	21%	-17%	10%
Dry	1.26	0.91	0.85	1.26	1.27	1.05	0.67	1.27	1%	13%	-27%	1%
Wet	0.32	0.91	0.85	1.26	0.31	1.05	0.67	1.27	-3%	13%	-27%	1%

	Surface Roughness Length (m)								Surface Roughness Length (m)			
	Middle Georgia Regional Airport				Site				Difference (%): Site - Airport			
Sector	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)
0 - 30	0.042	0.057	0.106	0.094	0.312	0.367	0.407	0.392	87%	84%	74%	76%
30 - 60	0.030	0.042	0.180	0.177	0.365	0.405	0.477	0.470	92%	90%	62%	62%
60 - 90	0.030	0.040	0.198	0.198	0.110	0.165	0.270	0.267	73%	76%	27%	26%
90 - 120	0.029	0.039	0.120	0.112	0.228	0.336	0.399	0.397	87%	88%	70%	72%
120 - 150	0.056	0.084	0.121	0.108	0.546	0.619	0.637	0.631	90%	86%	81%	83%
150 - 180	0.034	0.056	0.113	0.105	0.391	0.455	0.502	0.501	91%	88%	77%	79%
180 - 210	0.025	0.037	0.074	0.072	0.325	0.376	0.419	0.417	92%	90%	82%	83%
210 - 240	0.058	0.083	0.154	0.146	0.452	0.537	0.575	0.570	87%	85%	73%	74%
240 - 270	0.035	0.047	0.100	0.089	0.457	0.542	0.571	0.565	92%	91%	82%	84%
270 - 300	0.059	0.078	0.171	0.160	0.277	0.374	0.436	0.431	79%	79%	61%	63%
300 - 330	0.156	0.206	0.290	0.271	0.122	0.160	0.263	0.251	-28%	-29%	-10%	-8%
330 - 360	0.090	0.129	0.204	0.189	0.228	0.294	0.368	0.354	61%	56.1%	45%	47%
Average	0.054	0.075	0.153	0.143	0.318	0.386	0.444	0.437	83%	81%	66%	67%

"DJF" means December, January, and February
"MAM" means March, April, and May
"JJA" means June, July, August
"SON" means September, October, November
(All AERSURFACE default settings)

4.2.2 Urban versus Rural Dispersion Options

This section describes the performance of land-use analysis for the purpose of determining the type of dispersion coefficients most appropriate for the application. The two sets of dispersion coefficients available in AERMOD are urban and rural. The goal of this land-use analysis is to estimate the percentage of urban and rural types of land cover within the study area. The study area is defined as a region centered on the site and having a radius of 3 km. The land-use types corresponding to urban areas are the "Commercial/Industrial/ Transportation" and "High Intensity Residential" types, where all other land cover types are associated with a rural setting.

As specified in Section 7.2.1.1.b.i of the *Guideline*, a circular area with a 3 km radius centered at the Facility was considered for the land-use analysis. AERSURFACE (version 20060) was used to extract the land-use values in the domain. The results of the land-use analysis evaluation are provided in Table 4-2.

Table 4-2. Land-Use Categories Summary

Category ID	Category Description	Number of Grid Cells	Percent	Dispersion Class
11	Open Water	56	0.2%	Rural
21	Developed, Open Space	956	3.0%	Rural
22	Developed, Low Intensity	106	0.3%	Rural
23	Developed, Medium Intensity	41	0.1%	Urban
24	Developed, High Intensity	76	0.2%	Urban
31	Barren Land	38	0.1%	Rural
41	Deciduous Forest	3,664	11.7%	Rural
42	Evergreen Forest	6,655	21.2%	Rural
43	Mixed Forest	3,305	10.5%	Rural
52	Shrub/Scrub	2,211	7.0%	Rural
71	Grassland/Herbaceous	3,517	11.2%	Rural
81	Pasture/Hay	2,247	7.2%	Rural
82	Cultivated Crops	310	1.0%	Rural
90	Woody Wetlands	6,767	21.5%	Rural
95	Emergent Herbaceous Wetlands	1,474	4.7%	Rural
	Total	31,423	100%	
	Urban		0.4%	
	Rural		99.6%	

This summary was generated by AERSURFACE and stored in the run's log file. The 30 categories were evaluated according to the *Guideline* in terms of dispersion classes as being of URBAN or RURAL. As the data show, the domain surrounding the Facility is approximately 99.9% rural. Therefore, AERMOD was evaluated considering rural dispersion coefficients.

4.3 Receptor Grid Coordinate System

Modeled concentrations were calculated at ground-level receptors placed along the facility fenceline and on a variable Cartesian receptor grid. Fenceline receptors were spaced no more than 50 meters apart. Beyond the fenceline, receptors were placed with 100 meters spacing on a Cartesian grid extending out to a distance sufficient to resolve the maximum concentration. The assessment of the SIA utilized a 10 km receptor grid for CO, PM_{10}, $PM_{2.5}$ (NAAQS and Increment), annual NO_2 and 1-hr NO_2 for natural gas option only. For the 1-hr NO_2 averaging period under fuel oil operating scenario significance modeling, it was necessary to extend the receptor grid further to 50 km to encompass all receptors which were found to exceed the 1-hr NO_2 SIL. Due to the limitation of number of receptors for utilizing ARM2 for modeling NO_2, receptors were placed using variable density in order to avoid splitting the receptors into multiple model runs. Specifically, beyond the fenceline, receptors were placed with 100 meters spacing on a Cartesian grid extending out to 2 km from the fenceline, 250 meters spacing on a Cartesian grid extending out to 2 km to 5 km from the fenceline and 500 meters spacing on a Cartesian grid extending out to 5 km to 50 km from the fenceline. A graphical representation of the significance modeling results and the final significance modeling receptor grid utilized for the 1-hr NO_2 under fuel oil operating scenario Significance Analysis (and significant receptors found) is included in Appendix A.

In general, the receptors covered a region extending from all edges of the Facility ambient boundary to the point where impacts from the project are no longer expected to be significant. The boundary is defined as all areas that are fenced, as shown in Figure 2-2.

Please note that per EPA guidance, a reduced receptor grid with only the receptors at which maximum modeled concentrations exceed the SIL is required to be used for the NO_2 NAAQS modeling, and the $PM_{2.5}$ NAAQS and Increment modeling.[29] Therefore, NAAQS and Increment modeling results, presented in Section 5, are representative of modeled receptors for which the project's impact is significant, as determined via the Significance Analysis.

The air toxics modeling analysis, presented in Section 5 of this report, utilized 50 meter spacing for fenceline receptors and a 5 km grid surrounding the Facility at 100 meter spacing.

Receptor elevations and hill heights required by AERMOD were determined using the AERMAP terrain preprocessor (version 18081). Terrain elevations from the USGS 1-arc second NED were used for AERMAP processing. In all modeling analysis data files, the location of emission points, structures, and receptors were represented in the UTM coordinate system, zone 17, NAD 83.

Input and output AERMAP model runs are provided in Appendix E.[30]

4.4 Building Downwash

The effects of building downwash for each of the facility's stack emission points were evaluated in terms of the proximity of the stack to nearby structures. The purpose of this evaluation is to determine if stack discharges might become caught in the turbulent wakes of these structures leading to downwash of the plumes. Wind blowing around a building creates zones of turbulence that are greater than if the building were absent.

For these modeling analyses, the direction-specific building dimensions used as input to the AERMOD model were calculated using the U.S. EPA's BPIP PRIME, version 04274. BPIP PRIME is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.[31]

For the BPIP analysis, the structure elevations (buildings and stacks) were estimating using the AERMAP processor (version 18081) and the 1-arc second NED maps.

EPA has promulgated stack height regulations that restrict the use of stack heights in excess of "Good Engineering Practice" (GEP) in air dispersion modeling analyses. Under these regulations, that portion of a stack in excess of the GEP height is generally not creditable when modeling to determine source impacts. This essentially prevents the use of excessively tall stacks to reduce ground-level pollutant concentrations.

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[29] *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (Memorandum from Mr. Tyler Fox, U.S. EPA, to Regional Air Division Directors, March 1, 2011).

[30] Files provided include the AERMAP input and output files as well as the base NED file used for the assessment.

[31] U.S. EPA, Office of Air Quality Planning and Standards, Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised), Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

This equation is limited to stacks located within five times the lesser dimension (5L) of a building structure. Stacks located at a distance greater than 5L from a building structure are not subject to the wake effects of the structure. The wind direction-specific downwash dimensions and the dominant downwash structures used in this analysis are determined using BPIP. In general, the lowest GEP stack height for any source is 65 meters by default.[32] The BPIP evaluation indicates that none of the facility emission unit stacks exceed GEP stack height.

Input and output files from the BPIP downwash analysis are provided in the electronic files included with this report in Appendix E.

4.5 Modeled Emission Sources

As discussed in Section 3 of this report, the Significance Analysis evaluates the emission increases associated with the specific project, and does not take into consideration any regional off-site emissions sources or other facility emission sources. The NAAQS analysis considers both on-site and off-site sources of the emissions of concern. This section discusses the emission sources considered, emission rates, and modeling methods utilized in the Significance Analysis and NAAQS analysis.

4.5.1 Representation of Emission Sources

WCP modeled the project-associated sources for the Significance Analysis. This includes emissions increases from the facility's four simple cycle combustion turbine systems (T1-T4) and the two natural gas heaters H1 and H2).

The 110 horsepower (hp) diesel-fired emergency fire pump engine (P1) and the 519 hp diesel-fired auxiliary generator engine (G1) were not modeled as part of the significance analysis, as these units will not be modified or altered as part of this project. The two emergency engines at the facility are intermittent sources and, therefore, do no need to be included as an emission source in the refined modeling analysis.[33,34] Potential emissions from the two units are summarized in Table 4-3. The two units are subject to the area source RICE MACT (40 CFR 63 Subparts A and ZZZZ) as emergency engines and are required to comply with applicable requirements of 40 CFR 63 Subpart A and ZZZZ per Permit Condition 3.3.5. Per historical operating status of the two emergency engines, the two units will not be tested simultaneously and will only be tested intermittently a few times a year.

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[32] 40 CFR 51.100(ii)

[33] Tian, Di. "Modeling Questions for Potential Project in Georgia." Message to Justin Fickas. October 11, 2018.

[34] *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (Memorandum from Mr. Tyler Fox, U.S. EPA, to Regional Air Division Directors, March 1, 2011).

Table 4-3. Summary of Potential Emissions from the Emergency Fire Pump Engine (P1) and the Auxiliary Generator Engine (G1)

Pollutant	Emergency Fire Pump Engine (P1) (lb/hr)	Emergency Fire Pump Engine (P1) (tpy)	Auxiliary Generator Engine (G1) (lb/hr)	Auxiliary Generator Engine (G1) (tpy)
CO	0.73	0.18	3.47	0.87
NO_2	3.41	0.85	16.09	4.02
PM_{10}	0.24	0.06	1.14	0.29
$PM_{2.5}$	0.24	0.06	1.14	0.29

Additional information regarding the emergency generator and fire pump are as follows.

1. Emissions from these sources can be found in Appendix B of Volume I of this permit application, as well as Table 4-3 above. The emergency generator is an approximately 519 hp diesel fire unit, and the fire pump is an approximately 110 hp diesel fired unit. While emissions from both units are estimated at 500 hr/yr, the actual operational run time of the units is limited. At 500 hrs/yr NOx emissions from the two units are less than 5 tpy, CO emissions are approximately 1 tpy, and PM_{10}/$PM_{2.5}$ emissions are less than 0.5 tpy.

2. Testing of both units is typically done at least once a calendar quarter for approximately 30 minutes to 1 hour for each unit.

3. The sources conduct maintenance and readiness testing on an approximately quarterly basis, although there is no clearly defined schedule.

4. The sources are not routinely tested simultaneously.

5. Permit No. 4911-303-0039-V-08-0, issued 1/11/21, contains various permit conditions (e.g. Conditions No. 3.2.1, 3.2.2, 5.2.2) which ensure monitoring of hours of operation and maintaining the emission units as emergency units only.

As the operations of these emission units is intermittent, available modeling guidance (e.g. March 1, 2011 *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hr NO_2 National Ambient Air Quality Standard*) indicate that it would be inappropriate to modeling intermittent sources continuously, when modeling sources in that manner could have an inappropriate influence on modeled design values. Given the short term and intermittent nature of operation of these emission units, modeling of these units would have an inappropriate influence on modeling design concentrations given their actual limited use and operations. Therefore, the emergency generator and fire pump are not included in any modeling evaluations for the facility.

The future potential emissions of each source considered were evaluated in the model as a positive emission rate, where past actual emissions (as derived from project baseline data) were evaluated in the model as a negative emission rate.[35]

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[35] In the case of NO_2 modeling, concerns have been raised regarding use of negative emission rates with Tier 2/Tier 3 modeling options. As Tier 2 modeling methods (e.g. ARM2) are used for this project, significance modeling evaluated both the future potential emissions from the project, as well as the past actual (baseline emissions) in the model as part of

Since the 1-hr NO_2 Significance Analysis, annual NO_2 Significance Analysis, 24-hr $PM_{2.5}$ Significance Analysis and Annual $PM_{2.5}$ Significance Analysis exceeded the Class II SILs, a NAAQS (and Increment for $PM_{2.5}$ and annual NO_2) analysis incorporating nearby sources was required (cumulative impact analysis). For the cumulative impact analysis, all sources at the facility (with the exception of the emergency fire pump engine and the auxiliary engine) and the appropriate regional inventory sources were included at their potential emission rates.

WCP emissions sources modeled for the 1-hr NO_2 NAAQS analysis, annual NO_2 NAAQS and PSD Increment analyses, 24-hr PM2.5 NAAQS and PSD Increment analyses, and annual $PM_{2.5}$ NAAQS and PSD Increment analyses included the facility's four simple cycle combustion turbine systems (T1-T4) and the two natural gas heaters H1 and H2). As outlined in Section 4.5.3, modeling for this project considered operations at 100% load (as the normal site operating condition), and an additional series of SUSD assessments for the Significance Analysis for NO_2 and CO and for the 1-hr NO_2 NAAQS.

4.5.2 Startup/Shutdown Operation

Emissions from startup/shutdown (SUSD) operations of the turbines were modeled for the Significance Analysis for CO and for the 1-hr NO_2 NAAQS as those were the only pollutants and averaging periods which exceedance of the SILs could reasonably be influenced by the SUSD modeling. Details regarding the SUSD modeling are as follows.

- Two startup times, one at 4 AM and one at 10 AM, were included as separate modeling runs in the modeling assessment. These are expected high frequency startup times for WCP. In the assessment, the startup times of each turbine were assumed to be starting up simultaneously. This is a highly conservative evaluation of the startup emissions; actual site operational practices during cold starts involve no more than two turbines starting simultaneously.
- A cold startup cycle (approximately 1 hours) was the focus of the SUSD modeling, as it is the worst case SUSD condition based on the emissions and duration of startup.
- Startup source parameters (velocity/temperature/emissions) were developed for each hour of the startup cycle based on available data provided by WCP.

4.5.3 Variable Load Analysis

Stack exhaust gas flow rates and temperatures for simple cycle combustion systems are not linear with load. For example, the expected velocity/flow rate from one of the simple cycle combustion systems at 75% load is not "75% of the 100% value;" it is approximately 80% of the 100% load value. Therefore, the percent load does not directly equate to the percentage of expected flow/velocity and emissions at a given load, when compared to 100% load, and a minimum load does not directly correspond to a minimum emission rate and flow/velocity. What is important to consider is that as flow/velocity decreases, mass emissions have a corresponding decrease. While the emissions concentrations (ppm) at lower loads may or may not change from higher load operation, with a lower flow/velocity the mass emissions correspondingly decrease, thereby leading to reduced expected impacts to ambient air quality relative to the 100% load scenario.

Temperature is not as significantly impacted with lower loads. Available data indicates an approximately 19% decrease in temperature from the 100% load case down to the 50% load case. Therefore, decreased

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separate model runs with positive emission rates. Model plot file output data was then utilized to subtract the past actual model results from the future potential model results, so as no negative emission rates will be utilized in the dispersion model for NO_2 modeling.

temperatures at minimum load would not be expected to have much influence on dispersion from the simple cycle combustion turbine units, thus having no appreciable influence on ambient air quality.

What is most important to remember, is that the simple cycle combustion turbine units at the facility intend to operate for continuous periods at high loads (75% load or higher). Operations at minimum loads would only be expected to occur for short periods of time on an annual basis.

The source parameters for the simple cycle units (T1-T4) when operating at 50% load, 75% load, and 100% load were developed and evaluated to determine the worst-case modeled impacts for each applicable pollutant. That load basis (on a pollutant-by-pollutant basis), as shown in Section 5, demonstrated that the 100% load basis was the overall worst case modeling condition for all pollutants. Therefore, the 100% load condition was carried through as the normal operating condition in all modeling assessments for the project, including SIL, NAAQS, and Increment evaluations, for all pollutants and averaging periods.

Source parameters for the 100%, 75%, and 50% load conditions, utilized in the modeling assessment, are included in Appendix D.

4.5.4 Significance Analysis

The Significance Analysis was conducted to determine whether the emissions increases associated with the proposed project could cause a significant impact on the air quality of the surrounding area. “Significance” is analyzed based on modeling <u>only the emissions increases from new, modified, or associated sources</u> comprising the project; no existing unmodified or associated sources are included, nor are sources from other regional facilities.

“Significant” impacts are defined by design concentration thresholds commonly referred to as the SIL. For this project, significance modeling will include the facility simple cycle combustion turbines (as modified units) and the natural gas heaters (as associated sources). The emergency fire pump engine and the auxiliary engine were not be modeled as part of the significance analysis as detailed in Section 4.5.1

Emissions for significance were evaluated as follows:

- Evaluations for both use of fuel oil, as well as natural gas were evaluated separately and carried through all subsequent analyses (e.g. NAAQS analysis) separately for all short term (non-annual) averaging periods and annual averaging period except for NO_2. For the annual averaging period, an annual average emissions rate (based on both use of fuel oil and natural gas) for the facility combustion turbines were derived and carried through annual average analyses for NO_2.

- SUSD operations of the turbines were modeled for the Significance Analysis for NO_2 and CO.

- For the CO, PM_{10} and $PM_{2.5}$ Significance Analyses, the future potential emissions of each source were evaluated in the model as a positive emission rate, where past actual emissions (as derived from project baseline data) were evaluated in the model as a negative emission rate.

- For the NO_2 Significance Analysis, due to concerns regarding the use of negative emission rates with the Tier 2 modeling options used for this analysis (discussed in Section 4.5.5), separate significance modeling runs were conducted for the future potential emissions following the project and for the baseline past actual emissions preceding the project. In both cases, the emissions were modeled as positive emission rates. Model plot file output data were then utilized to subtract the maximum results at each receptor for baseline actual emissions model run from the maximum results at each receptor from the future potential emissions model run for comparison to the SIL, so no negative emission rates were utilized in the dispersion modeling for NO_2.

- Past actual emissions (based on the last 2 years data, unless otherwise noted) were derived through:
  - For NO_2 modeling, CEMS data as recorded by existing facility monitoring equipment, and reported to EPA under the Clean Air Markets Program, in combination with hours of operation to derive hourly emission rates.
  - For PM_{10}/$PM_{2.5}$, MMBtu heat input data and hours of operation (along with allowable emission rates in lb/MMBtu) were used to derive hourly emissions.
  - The Facility is considered a baseline source for $PM_{2.5}$ increment, as the facility was an existing permitted and operational facility as of the baseline date (October 2010) for $PM_{2.5}$. Therefore, for $PM_{2.5}$ increment purposes, the project emissions increase for $PM_{2.5}$ increment considered baseline emissions from the facility for calendar years 2009 and 2010 as representative of the baseline period for $PM_{2.5}$ increment impacts.
  - All non-annual averaging period emission rates, were based on short term average emissions (e.g. emissions divided by actual hours operated). Annual averaging period emissions were based on annualized emission rates (emissions divided by 8,760 hours).

Information demonstrating the derivation of the baseline source emissions, as well as tables providing the baseline modeling inputs utilized in both the significance (and NAAQS) analyses, can be found in Appendix D.

4.5.5 NO_2 Modeling Approach

The revised *Guideline* indicates Ambient Ratio Method 2 (ARM2) has replaced ARM as the regulatory default Tier 2 NO_2 modeling method. WCP has utilized ARM2 for modeling NO_2 for the 1-hour and annual SIL and NAAQS modeling assessments, as applicable, using the default conversion ratios. Significance modeling utilizing ARM2 was conducted for future potential emissions and for past actual emissions, both as positive emission rates in separate modeling files, and subtracting the maximum results at each receptor manually using plot file output information. This approach was approved by the Georgia EPD as part of the modeling protocol approval process.

All emissions data was input into the AERMOD model as NO_X, with the model providing output results in terms of NO_2. Electronic modeling files and spreadsheet data for the NO_2 modeling analyses are provided in Appendix E.

4.5.6 Tier 1 Analysis - Consideration of Modeled Emission Rates for Precursors (MERPs)

In accordance with the revised and updated 40 CFR 51, Appendix W, precursor emission impacts to ozone and $PM_{2.5}$ (secondary $PM_{2.5}$) must be considered as part of the modeling analysis. The precursors to ground-level ozone formation are VOC and NO_X, and the precursor emissions for secondary $PM_{2.5}$ formation are NO_X and SO_2. Georgia EPD guidance, as part of the February 2019 *Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia* was followed, as outlined in the following sections. MERPs were used to assess ozone-based impacts for the project, secondary $PM_{2.5}$ impacts based on project emissions increases for the modeling significance analysis, secondary $PM_{2.5}$ impacts from the facility for both NAAQS and PSD Increment modeling, an estimation of secondary $PM_{2.5}$ impacts for Class I SIL analyses, and an estimation of secondary $PM_{2.5}$ impacts from inventory based increment consumers (resultant from NO_2 increases since October 2010) for the PSD Increment analysis.

4.5.6.1 Ozone MERPS Assessment

As outlined in Table 2 of the EPD February 2019 guidance, the default MERP values (tpy) for Georgia PSD applications are 156 tpy NO_X and 3,980 tpy VOC for 8-hr ozone.

Per Equation 2 of the EPD guidance, the SIL analysis demonstration for the proposed project at WCP is as follows;

(565.97 tpy NO_X project emissions increase / 156 tpy NO_X 8-hr O_3 MERP) + (95.21 tpy VOC project emissions increase / 3,980 tpy VOC 8-hr O_3 MERP) = 3.63 + 0.02 = **3.65**

As the predicted ozone value is greater than the threshold value of 1, a cumulative analysis for ozone was performed. Per Equation 5 of the EPD guidance, the cumulative analysis demonstration for ozone is as follows:

$Background\_ozone$ (64 ppb) + 3.65 x SIL_ozone (1 ppb) = 67.65 ppb

As the cumulative ozone value is less than the NAAQS limit for ozone (70 ppb), the proposed project does not cause or contribute to a violation of the ozone NAAQS. A secondary reference for this calculation can be found in Table D-18 of Appendix D.

4.5.6.2 $PM_{2.5}$ MERPS Assessment – Class II SILs Analysis

As outlined in Table 2 of the EPD February 2019 guidance, the default MERP values (tpy) for Georgia PSD applications are 4,014 tpy NO_X, and 667 tpy SO_2 for daily $PM_{2.5}$, and 7,427 tpy NO_X and 6,004 tpy SO_2 for annual $PM_{2.5}$. Per EPA guidance and confirmation from EPD (Email from Mr. Byeong Kim dated April 9, 2021), only pollutants that trigger PSD should be included in Tier I MERPs evaluation. SO_2 emissions are below the SER for this propsoed project and therefore are not included in MERPs evaluation.

Per Example 1 of the EPD guidance, the SILs analysis demonstration is as follows;

For annual $PM_{2.5}$:

(565.97 tpy NO_X project emissions increase / 7,427 tpy NO_X Annual MERP) = 0.0762 = 0.0762× 100% = 7.62%

This effectively means, that so long as direct modeled impacts of annual $PM_{2.5}$ are less than 98% of the $PM_{2.5}$ SIL (0.2 µg/m^3), then impacts from the project are acceptable and less than the SIL when considering the additive secondary $PM_{2.5}$ on an annual basis for Class II modeling. This also means that there is a default secondary $PM_{2.5}$ modeled impact of 0.0152 µg/m^3 (7.62% of 0.2 µg/m^3) that could be applied to modeling for $PM_{2.5}$, for the annual averaging period.

For daily $PM_{2.5}$:

(565.97 tpy NO_X project emissions increase / 4,014 tpy NO_X Daily MERP) = 0.1410= 0.1410 × 100% = 14.10%

This effectively means, that so long as direct modeled impacts of daily $PM_{2.5}$ are less than 94.65% of the $PM_{2.5}$ SIL (1.2 µg/m^3), then impacts from the project are acceptable and less than the SIL when considering the additive secondary $PM_{2.5}$ on an annual basis for Class II modeling. This also means that there is a default secondary $PM_{2.5}$ modeled impact of 0.17 µg/m^3 (14.1% of 1.2 µg/m^3) that could be applied to modeling for $PM_{2.5}$, for the daily averaging period.

A secondary reference for the above calculations, can be found in Table D-18 of Appendix D.

The above considerations of additive effects of secondary $PM_{2.5}$ to direct primary $PM_{2.5}$ should be considered highly conservative, since it is highly unlikely that there would be temporal and spatial alignment of primary and secondary $PM_{2.5}$ impacts, particularly for the short term 24-hr averaging period in the near field of WCP, where modeled primary $PM_{2.5}$ impacts are at their highest.

4.5.6.3 $PM_{2.5}$ MERPS Assessment – Class II Refined NAAQS and PSD Increment Analyses

For any Class II refined NAAQS or Increment analyses, the facility's contribution to secondary $PM_{2.5}$ impacts should be considered. Therefore, in this case the facility wide emissions of NOx, post project, should be considered for the facility secondary $PM_{2.5}$ contribution to NAAQS associated impacts. The facility wide PTE after the project was also conservatively used to address the secondary $PM_{2.5}$ contributions for NO_2 associated facility emission increases to $PM_{2.5}$ Increment impacts.

For annual $PM_{2.5}$:

(624.48 tpy NO_X facility wide PTE / 7,427 tpy NO_X Annual MERP) * 0.2 µg/m^3 = 1.68E-02 µg/m^3

So, for the NAAQS analyses, the secondary $PM_{2.5}$ contribution from the facility was conservatively estimated as 1.68E-02 µg/m^3 for the annual averaging period.

For daily $PM_{2.5}$:

(624.48 tpy NO_X facility wide PTE / 4,014 tpy NO_X Daily MERP) * 1.2 µg/m^3 = 0.19 µg/m^3

So, for the NAAQS analyses, the secondary $PM_{2.5}$ contribution from the facility was conservatively estimated as 0.19 µg/m^3 for the daily/24-hr averaging period.

While background monitoring data is considered to account for secondary $PM_{2.5}$ from regional inventory sources for a refined NAAQS analysis, a PSD Increment evaluation does not consider background monitoring data. Therefore, it was necessary to account for the potential secondary $PM_{2.5}$ impacts from increment consumers after the October 2010 baseline date for $PM_{2.5}$. This was done as follows;

1. Identified NO_2 modeling inventory sources were reviewed to find those sources which had permitting actions conducted on or since October 2010.
2. If a facility had no permitting actions since October 2010 which added or modified facility emission units, or otherwise affected the facility potential to emit, it was considered a baseline source with no appreciable consumption of increment occurring associated with NO_x emissions.
3. If a facility had permitting actions since October 2010 which added or modified facility emission units, or otherwise increased the facility production/potential to emit, etc. then the facility potential increase in emissions associated with those projects was considered to be a consumption of secondary $PM_{2.5}$ associated with NO_x emissions.
4. Some facilities had limited online permitting documentation, so their identified facility wide PTE for NO_x was conservatively assumed to be consumption of secondary $PM_{2.5}$ associated with NO_X emissions.

This created a total inventory based NOx emissions for consumption of increment of 1,698.71 tpy. This was conservatively combined with the facility wide PTE for NO_X emissions from WCP (624.48 tpy) to create a total potential MERP based contribution to the PSD Increment analysis of approximately 2,323 tpy.

This created a secondary $PM_{2.5}$ MERP addition for the annual averaging period for the PSD Increment analysis as follows.

For annual $PM_{2.5}$:

(2,323 tpy NO_X facility wide PTE and Inventory Emissions / 7,427 tpy NO_X Annual MERP) * 0.2 µg/m^3 = 6.26E-02 µg/m^3

So, for the PSD Increment analyses, the secondary $PM_{2.5}$ contribution from the facility and regional inventory sources was conservatively estimated as 6.26E-02 µg/m^3 for the annual averaging period.

For daily $PM_{2.5}$:

(2,323 tpy NO_X facility wide PTE and Inventory Emissions / 4,014 tpy NO_X Daily MERP) * 1.2 µg/m^3 = 0.69 µg/m^3

So, for the PSD Increment analyses, the secondary $PM_{2.5}$ contribution from the facility and regional inventory was conservatively estimated as 0.69 µg/m^3 for the daily/24-hr averaging period.

More information regarding the regional inventory NOx emissions used, and documentation regarding the calculations referenced above, can be found in Table D-19 and D-21 of Appendix D.

4.5.6.4 $PM_{2.5}$ MERPS Assessment – Class I SILs Analyses

For $PM_{2.5}$ for the Class I SILs assessment, the contribution of secondary $PM_{2.5}$ from project associated NOx emissions was considered. A representative source was chosen as the Allendale, SC hypothetical source from the EPA MERPSs View Qlik website (https://www.epa.gov/scram/merps-view-qlik) based on the proximity to the WCP facility and similar topography/climate as the WCP facility. Data was extracted from Qlik for the approximate distance to the closest Class I area (220 km) and data for the 1,000 tpy source with a 90 ft. tall stack (same stack height as WCP turbines). The project emissions were then used to scale the indicated concentrations at that distance (220 km) to derive an annual secondary $PM_{2.5}$ MERP contribution of 2.76E-04 µg/m^3 and 9.99E-03 µg/m^3 contribution for the daily averaging period.

Additional details regarding this calculation can be found in Table D-20 of Appendix D.

4.5.7 Class I Visibility Analysis

Visibility can be affected by plume impairment (heterogeneous) or regional haze (homogeneous). Plume impairment results when there is a contrast or color difference between the plume and a viewed background (the sky or a terrain feature). Plume impairment is generally only of concern when the Class I area is near the proposed source (i.e., less than 50 km). None of the Class I area is within 50 km of WCP, therefore, Class I visibility analysis is not performed. As discussed previously, regional haze (occurs at distances beyond 50 km) was not addressed for this project given the low Q/D ratios associated with the proposed increases.[36]

[36] See Section 3.5 for information regarding correspondence with the FLMs on this issue.

5. SUMMARY OF RESULTS

This section summarizes the results of the dispersion modeling analyses. Electronic copies of modeling files are included in Appendix E.

5.1 Turbine Load Analysis

As discussed in Section 4.5.3, a load analysis evaluating modeled impacts at 100%, 75%, and 50% load for the facility's four simple cycle combustion units was conducted. The results of that analysis are shown in Table 5-1.

Table 5-1. Turbine Load Analysis

Pollutant	Averaging Period	5-Year Average?[1]	Modeled Output	Load Analysis Modeled Conc. ($\mu g/m^3$)[2] 100%	75%	50%
$PM_{2.5}$	24-hour	Yes	H1H	**0.55**	0.54	0.44
	Annual	Yes	H1H	**4.44E-02**	4.29E-02	3.51E-02
PM_{10}[3]	24-hour	No	H1H	**0.93**	0.78	0.64
	Annual	No	H1H	**4.93E-02**	4.62E-02	3.78E-02
CO	1-hour	No	H1H	**19.19**	16.50	12.19
	8-hour	No	H1H	**7.64**	6.34	4.64
NO_2	1-hour	Yes	H1H	**35.26**	30.38	22.54
	Annual	No	H1H	**5.76E-02**	5.40E-02	4.43E-02

1. Note that a 5-year concatenated Met Data set should only be used for the pollutants/averaging periods that are approved to use 5-year averaging.
2. Based on fuel oil scenario. Results are the maximum of 5 individual year runs if no 5-year average was used.
3. PM_{10} load analysis should represent $PM_{2.5}$ for Increment purpose as the turbine as the same emission rates for PM_{10} and $PM_{2.5}$ and with individual year of meteorological data.

Based on the results above, all analyses indicate the 100% load condition was shown to the be worst case modeling condition. Therefore, the 100% load case was used for all modeling significance analyses.

5.2 Class II and Class I Significance Analyses

As discussed in Sections 3.1 and 3.5, Significance Analyses for Class II and Class I areas, respectively, were conducted to determine the need for further pollutant modeling. Modeled emission points, parameters, and emission rates for the Significance Analyses are provided in Appendix D.

The results of the Significance Analyses for each pollutant are provided in Table 5-2 and represent the maximum modeled concentrations from the significance runs. For pollutants and averaging periods modeled with separate meteorological files for the five-year period evaluated, the "Year" listed in the tables corresponds to the individual year for which maximum impacts were observed. Results for both natural gas operation and fuel oil operation for facility turbine units are evaluated and summarized in Table 5-2. All modeled results reported for the Significance Analysis correspond to H1H modeled impacts.

As discussed in Section 4.5.2, an evaluation of the modeled impacts from periods of SUSD was included in Significance Analysis for 1-hr NO_2, 1-hr CO and 8-hr CO. The scenarios evaluated included the following:

- Normal site operations at 100% load for the entire day.
- SUSD for facility turbine units starting at 4 AM, with normal operation for the remainder of the day.
- SUSD for facility turbine units starting at 10 AM, with normal operation for the remainder of the day.

SUSD modeling was conducted utilizing the HROFDY functionality of the AERMOD model, conservatively assuming that a SUSD event would occur every day starting at either 4 AM or 10 AM. Modeling source parameters utilized in the Significance Analysis can be found in Appendix D.

Significant receptors derived for $PM_{2.5}$ increment modeling were used for both $PM_{2.5}$ NAAQS and increment modeling as they are more conservative.

Table 5-2. Class II Significance Results for $PM_{2.5}$ PM_{10}, CO and NO_2

Pollutant	Averaging Period	5-Year Average	Model Output	Scenario	Natural Gas Operation[1] Modeled Conc. (μg/m³)	PM2.5 MERP Contribution (μg/m³)	Total PM2.5 Impact (μg/m³)	SIL (μg/m³)	Exceeds SIL?	Radius of SIA (km)	Fuel Oil Operation[1] Modeled Conc. (μg/m³)	PM2.5 MERP Contribution (μg/m³)	Total PM2.5 Impact (μg/m³)	SIL (μg/m³)	Exceeds SIL?	Radius of SIA (km)
$PM_{2.5}$ [2]	24-Hour	Yes	H1H	Normal	2.80	0.17	2.97	1.2	Yes	0.36	2.81	0.17	2.98	1.2	Yes	0.36
	Annual	Yes	H1H	Normal	0.22	1.52E-02	0.24	0.2	Yes		0.22	1.52E-02	0.24	0.2	Yes	
	24-Hour	No	H1H	Normal	4.23	0.17	4.40	1.2	Yes		4.23	0.17	4.40	1.2	Yes	
	Annual	No	H1H	Normal	0.24	1.52E-02	0.26	0.2	Yes		0.24	1.52E-02	0.26	0.2	Yes	
PM_{10}	24-Hour	No	H1H	Normal	4.23			5	No		4.23			5	No	
	Annual	No	H1H	Normal	0.24			1	No		0.24			1	No	
CO	1-Hour	No	H1H	Normal	106.45			2,000	No		106.45			2,000	No	
				4 am Startup	106.45			2,000	No		106.45			2,000	No	
				10 am Startup	106.45			2,000	No		106.45			2,000	No	
	8-Hour	No	H1H	Normal	59.96			500	No		60.00			500	No	
				4 am Startup	59.96			500	No		60.00			500	No	
				10 am Startup	59.96			500	No		60.00			500	No	
NO_2 [3]	1-hour	Yes	H1H	Normal	100.09			7.5	Yes	1.77	103.76			7.5	Yes	41.09
				4 am Startup	100.09			7.5	Yes		103.76			7.5	Yes	41.09
				10 am Startup	100.09			7.5	Yes		103.70			7.5	Yes	50
	Annual	No	H1H	Normal	2.52			1	Yes	0.59						

1. Annual concentrations except for NO_2 are overly conservative as the modeled concentrations are based on short-term emission rates and do not account for reduced annual operational times for the turbines. Natural gas operation is expected for 3,000 hours per year, and fuel oil operation is expected for 500 hours per year.
2. $PM_{2.5}$ results include MERPs contribution to the predicted modeled impact.
3. Annual averaging period for NO_2 were based on annualized emission rates (emissions divided by 8,760 hours). Therefore, emissions for Natural Gas and Fuel Oil operations are the same.

As shown in Table 5-2, all CO and PM_{10} modeled impacts modeled impact are less than the applicable Class II SILs. As such, by definition, the project do not cause or contribute to an exceedance of the NAAQS or Class II Increment for CO and PM_{10}. However, $PM_{2.5}$ exceeded the Class II SIL for both the annual and 24-hr averaging period and NO_2 exceeded the Class II SIL for both the annual and 1-hr averaging period. MERPs contribution to the predicted modeled impact, as derived in the analysis in Section 4.5.6, are considered in Table 5-2. As a result, refined analyses for the $PM_{2.5}$ and NO_2 are required and are summarized in subsequent sections.

Also, as can be seen from Table 5-2, CO predicted modeled impacts for the project are below the 575 $\mu g/m^3$ SMC for the 8-hr averaging period and PM_{10} predicted modeled impacts for the project are below the 10 $\mu g/m^3$ SMC for the 24-hr averaging period.

As previously described in Section 4.5.4 and 4.5.5, modeled results for the Class II Significance Analysis for NO_2 (annual and 1-hr) were evaluated using separate model runs for future potential and for past actual emissions. Those model runs, provided in Appendix E, are annotated along with connotations of "PAST" or "FUTURE" to signify which model run is for which situation. As these model runs utilized ARM2, maximum modeled results were evaluated (FUTURE – PAST), on a receptor-by-receptor basis, to compare to the significance modeling results. Accompanying spreadsheets in the electronic modeling files within Appendix E include the receptor-by-receptor analysis (data extracted from NO_2 modeling plot files) to derive the final significance results displayed in Table 5-2.

Table 5-3. Class I Significance Results for PM_{10}, $PM_{2.5}$, and NO_2

				Natural Gas Operation[1]					Fuel Oil Operation[1]				
Pollutant	Averaging Period	Year	Model Output	Modeled Conc. ($\mu g/m^3$)	$PM_{2.5}$ MERP Contribution ($\mu g/m^3$)	Total $PM_{2.5}$ Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Exceeds SIL?	Modeled Conc. ($\mu g/m^3$)	$PM_{2.5}$ MERP Contribution ($\mu g/m^3$)	Total $PM_{2.5}$ Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Exceeds SIL?
$PM_{2.5}$[2]	24-Hour	No	H1H	1.56E-02	9.99E-03	2.56E-02	0.27	No	3.15E-02	9.99E-03	4.15E-02	0.27	No
	Annual	No	H1H	9.27E-03	2.76E-04	9.55E-03	0.05	No	1.03E-02	2.76E-04	1.06E-02	0.05	No
PM_{10}	24-Hour	No	H1H	1.52E-02			0.3	No	3.11E-02			0.3	No
	Annual	No	H1H	9.72E-03			0.2	No	1.08E-02			0.2	No
NO_2[3]	Annual	No	H1H	1.48E-02			0.1	No					

1. Annual concentrations are overly conservative as the modeled concentrations are based on short-term emission rates and do not account for reduced annual operational times for the turbines. natural gas operation is expected for 3,000 hours per year, and fuel oil operation is expected for 500 hours per year.
2. $PM_{2.5}$ results include MERPs contribution to the predicted modeled impact.
3. Annual averaging period for NO_2 were based on annualized emission rates (emissions divided by 8,760 hours). Therefore, emissions for Natural Gas and Fuel Oil operations are the same.

As shown in Table 5-3, the direct modeled impacts were below the applicable Class I SILs for the receptors along the 50 km-radius ring of receptors evaluated in AERMOD (provided in Appendix E). MERPs contribution to the predicted modeled impact, as derived in the analysis in Section 4.5.6, are considered in Table 5-3.

5.3 NAAQS Analysis

A NAAQS modeling analysis was conducted for the 1-hr NO_2 NAAQS, the annual NO_2 NAAQS, the 24-hr $PM_{2.5}$ NAAQS and the annual $PM_{2.5}$ NAAQS as those were the only applicable pollutants and averaging periods for which the Significance Analysis results exceeded the Class II SIL. As described in Section 4.3, the NAAQS and Increment analyses utilized the significant receptors (as derived from the Significance Analysis) for use in the refined analysis.

As discussed in Section 4.5.2, an evaluation of the modeled impacts from periods of SUSD was included in the 1-hr NO_2 NAAQS modeling analysis. The scenarios evaluated in the 1-hr NO_2 NAAQS analysis included the following:

- Normal site operations at 100% load for the entire day.
- SUSD for facility turbine units starting at 4 AM, with normal operation for the remainder of the day.
- SUSD for facility turbine units starting at 10 AM, with normal operation for the remainder of the day.

SUSD modeling was conducted utilizing the HROFDY functionality of the AERMOD model, conservatively assuming that a SUSD event would occur every day starting at either 4 AM or 10 AM.

Modeling source parameters utilized in the NAAQS modeling assessment can be found in Appendix D. The NAAQS analysis included the facility simple cycle combustion turbines, the natural gas heaters, and off-site inventory sources as outlined in Section 3.6 of this report.

Table 5-4. $PM_{2.5}$ NAAQS Analysis Results

Pollutant	Averaging Period	5-Year Average	Model Output	Fuel Option	Modeled Conc. (µg/m^3)	$PM_{2.5}$ MERP Contribution (µg/m^3)	Backround Conc. (µg/m^3)	Modeled +MERP + Backround Conc. (µg/m^3)	NAAQS (µg/m^3)	Exceeds NAAQS?	Modeled Percentage of NAAQS (%)
$PM_{2.5}$	24-hour	Yes	H8H	NG	4.47	0.19	18.4	23.06	35	No	65.87%
$PM_{2.5}$	Annual	Yes	H1H	NG	0.89	1.68E-02	7.9	8.81	12	No	73.41%
$PM_{2.5}$	24-hour	Yes	H8H	FO	4.47	0.19	18.4	23.06	35	No	65.89%
$PM_{2.5}$	Annual	Yes	H1H	FO	0.89	1.68E-02	7.9	8.81	12	No	73.43%

As the data show, predicted modeled impacts for the 24-hr and annual $PM_{2.5}$ NAAQS analysis demonstrate that WCP will not cause or contribute to any violation of the NAAQS.

Table 5-5. NO_2 Annual NAAQS Analysis Results

Pollutant	Averaging Period	5-Year Average	Model Output	Modeled Conc. (µg/m^3)	Backround Conc. (µg/m^3)	Modeled + Backround Conc. (µg/m^3)	NAAQS (µg/m^3)	Exceeds NAAQS?	Modeled Percentage of NAAQS (%)
NO_2	Annual	No	H1H	3.84	4.50	8.34	100	No	8.34%

As the data show, predicted modeled impacts for the annual NO_2 NAAQS analysis demonstrate that WCP will not cause or contribute to any violation of the NAAQS.

Table 5-6. 1-Hr NO_2 NAAQS Analysis Results

Pollutant	Averaging Period	5-Year Average	Model Output	Fuel Option	Scenario	Modeled Conc. (µg/m^3)	Backround Conc. (µg/m^3)	Modeled +Backround Conc. (µg/m^3)	NAAQS (µg/m^3)	Exceeds NAAQS?	Modeled Percentage of NAAQS (%)
NO_2	1-hour	Yes	H8H	Natural Gas	Normal	66.9	30.30	97.20	188	No	51.7%
NO_2	1-hour	Yes	H8H		4 am Startup	66.9	30.30	97.20	188	No	51.7%
NO_2	1-hour	Yes	H8H		10 am Startup	66.9	30.30	97.20	188	No	51.7%
NO_2	1-hour	Yes	H8H	Fuel Oil	Normal	374.5	30.30	404.78	188	Yes	215.3%
NO_2	1-hour	Yes	H8H		4 am Startup	374.5	30.30	404.78	188	Yes	215.3%
NO_2	1-hour	Yes	H8H		10 am Startup	374.5	30.30	404.78	188	Yes	215.3%

As the data show, predicted modeled impacts for the 1-hr NO_2 NAAQS analysis demonstrated that the WCP will not cause or contribute to any violations of the 1-hr NO_2 NAAQS under natural gas option. However, under the fuel oil option, predicted modeled impacts for 5 receptors exceeded the 1-hr NO_2 NAAQS analysis.

Therefore, a contribution analysis was conducted for the 5 receptors that exceeded the 1-hr NO_2 NAAQS for emission sources from WCP and off-site inventory sources for receptors.

Table 5-7. 1-Hr NO_2 NAAQS Contribution Analysis Results – Fuel Oil Option

Receptors UTM17 East (m)	Receptors UTM17 North (m)	Rank	Scenario	Modeled Conc. (µg/m³) All	Modeled Conc. (µg/m³) WCP	Modeled Conc. (µg/m³) Inventory	Contribution Percentage WCP	Contribution Percentage Inventory
290689.4	3637242.4	8th	Normal	374.48	1.42E-03	374.48	0.000%	100.000%
		8th	4 am Startup	374.48	1.42E-03	374.48	0.000%	100.000%
		8th	10 am Startup	374.48	1.42E-03	374.48	0.000%	100.000%
286689.4	3663242.4	8th	Normal	283.11	2.34E-03	283.11	0.001%	99.999%
		8th	4 am Startup	283.11	2.34E-03	283.11	0.001%	99.999%
		8th	10 am Startup	283.11	2.34E-03	283.11	0.001%	99.999%
301189.4	3636742.4	8th	Normal	196.31	1.84E-03	196.31	0.001%	99.999%
		8th	4 am Startup	196.31	1.84E-03	196.31	0.001%	99.999%
		8th	10 am Startup	196.31	1.84E-03	196.31	0.001%	99.999%
300689.4	3636742.4	8th	Normal	195.43	1.40E-03	195.43	0.001%	99.999%
		8th	4 am Startup	195.43	1.42E-03	195.43	0.001%	99.999%
		8th	10 am Startup	195.43	1.40E-03	195.43	0.001%	99.999%
291189.4	3637242.4	8th	Normal	171.58	1.62E-03	171.58	0.001%	99.999%
		8th	4 am Startup	171.58	1.65E-03	171.58	0.001%	99.999%
		8th	10 am Startup	171.58	1.62E-03	171.58	0.001%	99.999%

As shown in Table 5-7, WCP will not cause or contribute to any violations of the 1-hr NO_2 NAAQS. While the table above only shows the 8th highest contributions, the MAXDCONT output files in the contribution run folder provided in Appendix E (under NO_2, 1-hr, FO) demonstrate that until modeling exceedances are resolved (83rd high) WCP does not cause or contribute to any of the predicted modeled exceedances.

5.4 Class II Increment Analysis

A refined Class II PSD Increment analysis was conducted for annual NO_2, 24-hr $PM_{2.5}$ and annual $PM_{2.5}$. The analysis was conservative, as the same modeling inventory developed for the NAAQS analysis was utilized in the Increment analysis. The contribution from actual increment consumers to NO_2 or $PM_{2.5}$ impacts should only be less, as not all NAAQS sources will be NO_2 or $PM_{2.5}$ increment consumers. Additionally, no credit is taken for any increment expanders.

Modeling results representing the annual maximum modeled impacts for the annual NO_2, 24-hr $PM_{2.5}$ and annual $PM_{2.5}$ Increment analysis are summarized in Table 5-8.

Table 5-8. Class II Increment Analysis Results

Pollutant	Averaging Period	5-Year Average	Model Output	Fuel Option	Modeled Conc. (µg/m³)	$PM_{2.5}$ MERP Contribution (µg/m³)	Total $PM_{2.5}$ Impact (µg/m³)	Class II Increment (µg/m³)	Exceeds Increment?	Modeled Percentage of Increment (%)
NO_2	Annual	No	H1H	--	4.09	--	--	25.00	No	16.35%
$PM_{2.5}$	24-hour	No	H2H	NG	6.66	0.69	7.35	9.00	No	81.69%
$PM_{2.5}$	24-hour	No	H2H	FO	6.66	0.69	7.36	9.00	No	81.77%
$PM_{2.5}$	Annual	No	H1H	NG	0.96	6.26E-02	1.02	4.00	No	25.55%
$PM_{2.5}$	Annual	No	H1H	FO	0.96	6.26E-02	1.02	4.00	No	25.60%

As the data show, predicted modeled impacts for annual NO_2, 24-hr $PM_{2.5}$ and annual $PM_{2.5}$ Increment analysis demonstrated that WCP will not cause or contribute to any violation of the annual Class II PSD Increment. The analysis conservatively considered the MERPs contribution to both the significant analysis and the refined analysis for the PSD Increment.

5.5 Soil and Vegetation Impacts

Two comparisons were used to address potential soil and vegetation impacts. First, the significance results for modeled criteria pollutants that were below the SIL (PM_{10} and CO) and the NAAQS modeling results for $PM_{2.5}$ and NO_2 were assessed against the secondary NAAQS standards, which provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Second, modeled impacts for air toxics impacts were compared against conservative screening levels provided by the EPA specifically to address potential soil and vegetation impacts.[37]

As shown in Table 5-9, the impacts for each pollutant are below the applicable secondary NAAQS or the EPA screening levels. Thus, there are no adverse impacts expected on soils or vegetation as a result of the proposed project.

[37] U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078), 1981.

Table 5-9. Soil and Vegetation Impacts

Pollutant	Averaging Period	Total Concentration[1] (μg/m³)	Vegetation Sensitivity[2] Sensitive (μg/m³)	Intermediate (μg/m³)	Resistant (μg/m³)	Secondary NAAQS (μg/m³)	Minimum Threshold (μg/m³)	Threshold Exceeded?
NO_2	4-Hour	-	3,760	9,400	16,920	N/A	3,760	No
	8-Hour	-	3,760	7,520	15,040	N/A	3,760	No
	1-Month	-	-	564	-	N/A	564	No
	Annual	8.34	-	94	-		94	No
PM_{10}	24-hour	4.23	-	-	-	150	150	No
	Annual	0.24	-	-	-	50	50	No
$PM_{2.5}$	24-hour	22.95	-	-	-	35	35	No
	Annual	8.80	-	-	-	15	15	No
SO_2[3]	1-hour	-	917	-	-	N/A	917	No
	3-hour	-	786	2,096	13,100	1,300	786	No
	Annual	-	-	18	-	N/A	18	No
CO[3]	1-wk	-	1,800,000	-	18,000,000	N/A	1,800,000	No
H_2S[3]	4-hour	-	28,000	-	560,000	N/A	28,000	No
Ethylene[3]	3-hour	-	-	47	-	N/A	47	No
	24-hour	-	-	1.2	-	N/A	1.2	No
Fluorine[3]	10-Days	-	-	0.5	-	N/A	0.5	No
Beryllium[3]	1-Month	-	-	0.01	-	N/A	0.01	No
Lead[3]	3-Months	-	-	1.5	-	0.15	0.15	No

1. Results from the PM_{10} (24-hour and annual) SIL runs were used since a NAAQS analysis was not required.
2. Screening concentrations based on Table 3.1 in "*A Screening Procedure for Impact of Air Pollution Sources on Plants, Soil and Animals*" , EPA, December 12, 1980. Minimum values noted if range listed.
3. Modeling was not required for SO_2, CO, H_2S, ethylene, fluorine, beryllium, and lead for this project. Hence, compliance with these limits is inherent.

5.6 Class II Visibility Analysis

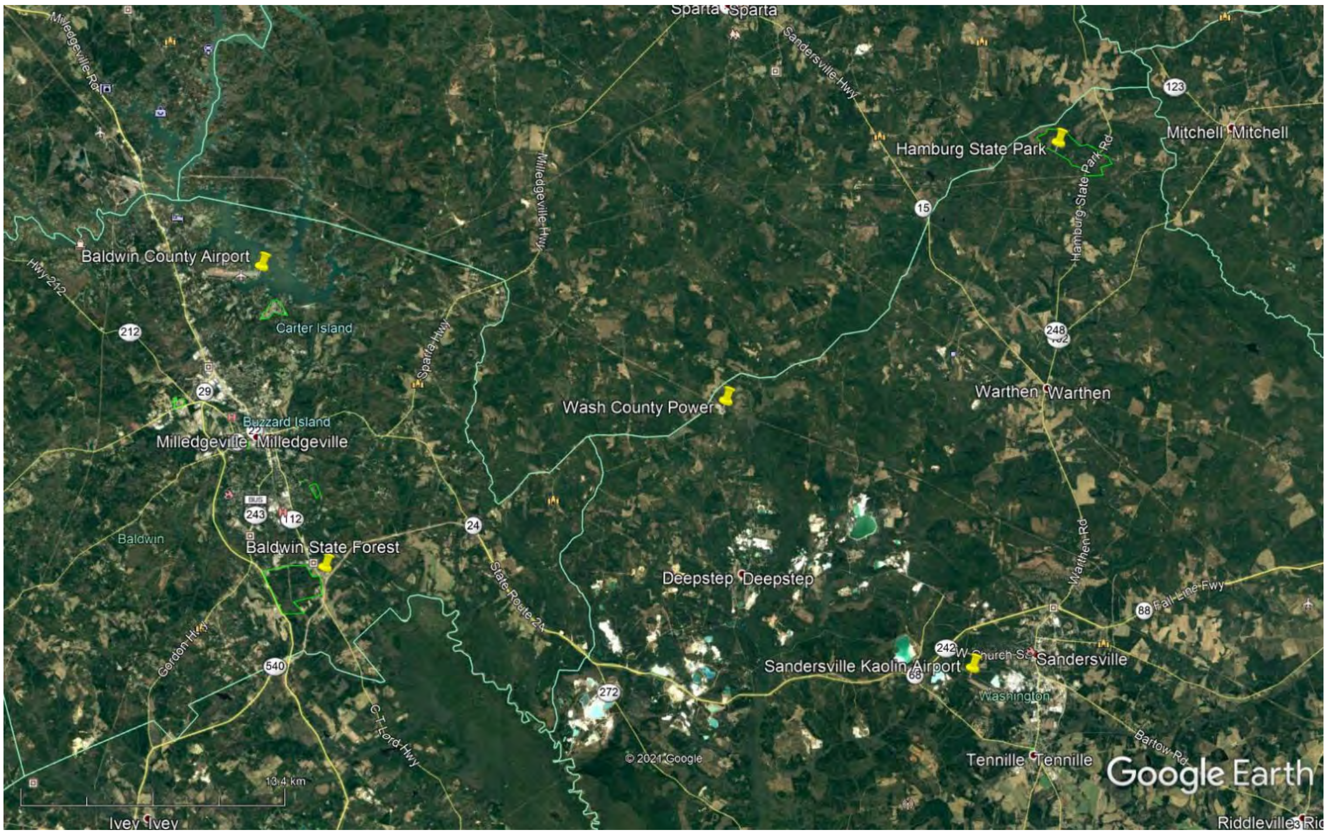
This section discusses the near-field plume visibility analysis that was performed to assess the proposed project impacts on visibility for nearby areas of interest, which are sensitive receptors (e.g., state parks, airports) within the modeled significant impact area for a visibility-affecting pollutant. In this case, the 1-hr NO_2 significant impact area was significant (larger than 40 km). The four closest potentially impacted Class II visibility based areas were selected for analysis, as any other areas further in distance than those selected should only have improved modeling results.

5.6.1 Public Vista Determination

A visibility impairment analysis is required to demonstrate that emissions from the proposed modifications will not have an adverse impact on visibility in the vicinity of the plant. Elements of the visibility impairment analysis include determining the visual quality of the area and assessing the visual impact of the proposed modifications on nearby sensitive receptor areas. Washington County Power determined the 4 nearest areas of interest to the facility to be (also shown below in Figure 5-1):

- Sandersville/Kaolin Airport – approximately 18 km to the southeast;
- Hamburg State Park – approximately 20 km to the northeast;
- Baldwin State Forest – approximately 21 km to the west-southwest; and
- Baldwin County Airport – approximately 24 km to the west-northwest

Figure 5-1. Map of Class II Visibility Areas of Concern Evaluated



5.6.2 VISCREEN Modeling Methodology

The EPA's *Workbook for Plume Visual Impact Screening and Analysis*[38] (referred to herein as the Workbook) provides guidance for conducting a visibility impairments analysis using VISCREEN, a plume visibility impact model. The methods in this workbook are designed for Class I area impacts; however, the procedures are generally applicable to other areas[39] and therefore are used in this analysis. See Appendix E for the VISCREEN model output files.

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[38] U.S. EPA Office of Air Quality Planning and Standards. Workbook for Plume Visual Impact Screening and Analysis. Research Triangle Park, NC. EPA-450/4/88/015. September 1988.

[39] New Source Review Workshop Manual (Draft), p. D.6.

VISCREEN allows for two levels of visibility impact screening. Level 1 screening involves a series of conservative calculations designed to identify those emissions sources that have little potential for adversely affecting visibility. If visibility impairments are indicated, a Level 2 analysis, which allows for modification of default parameters including meteorological data, is performed. Since the Level 1 assumptions were anticipated to be much too conservative, a Level 2 analysis was performed for this project for the Class II visibility areas of interest.

Results from a VISCREEN analysis are expressed in terms of perceptibility (ΔE) and contrast. The color contrast parameter, ΔE, is used as the primary basis for determining the perceptibility of plume visual impacts in screening analyses. ΔE provides a single measure of the difference between two arbitrary colors as perceived by humans. The Workbook suggests a critical value for ΔE of 2.0 for untrained observers under reasonable worst-case conditions. A green contrast value is also recorded because the human eye is most sensitive to intensity changes in green. The critical value for this contrast is 0.05. VISCREEN may re-estimate these critical values based on inputs during the analysis.

As discussed in the Workbook, VISCREEN conducts four tests of screening calculations. The first two tests refer to visual impacts caused by plume parcels located **inside** the boundaries of the given area. Tests of impacts inside the boundary are used to determine visual impacts when integral vistas are not protected. The last two tests are for plume parcels located **outside** the boundaries of the area. The tests of visual impacts outside the boundaries of Class I areas are only required if analyses for protected integral vistas are required. An integral vista is a view from a location inside a Class I area of landscape features located outside the boundaries of the Class I area. Because there are no protected integral vistas outside of the pseudo-Class I area chosen in this analysis, the tests for plume parcels located **outside** the boundaries of these points were not required. The tests of visual impacts inside the boundaries of the areas were the only tests considered in the VISCREEN analysis.

5.6.3 VISCREEN Input Requirements and Methodology

As previously discussed, the Level 1 modeling procedure was bypassed and only a Level 2 analysis was performed. The input parameters used in the modeling were set equal to the Level 1 values with the exception of the modeled meteorological conditions and background ozone. The background ozone value was updated from 0.04 ppm to 0.06 ppm to be more reflective of the project location. The modeled emission rates were as follows:

- PM – 107.35 lb/hr
- NOx (as NO_2) – 950.82 lb/hr – conservatively assuming that NO_2 are 90% of NOx.
- Primary SO_4 – 3.04 lb/hr – conservatively assumes all sulfuric acid mist is sulfate.

The modeled PM, H_2SO_4 (as primary sulfate) and NO_2 emission rates are the maximum short-term rates and were conservatively based on the assumption that all turbines would be operating simultaneously and continuously on fuel oil. This is especially conservative as the maximum short term emission rates are based on use of fuel oil, that will be used intermittently during normal source operation. As specified in the Workbook for Plume Visual Screening and Analysis, SO_2 emissions are not required as a VISCREEN input. This is because the analysis focuses on the short-term effects of emitted pollutants upon visibility. Sulfur dioxide does not have a significant effect upon visibility. Over time, SO_2 will oxidize to sulfate, which does affect visibility. However, an insignificant amount of sulfate is formed in the short time under consideration in a VISCREEN analysis.

5.6.4 Determination of Modeled Meteorological Conditions

A Level 1 VISCREEN analysis uses an assumed worst-case meteorological condition of F stability and a wind speed of 1 m/s. The actual meteorological conditions for the project area were reviewed to determine a worst-case meteorological condition that could transport the project emissions to the region of interest and beyond. Washington County Power used the AERMOD meteorological data files from the other Class II modeling analyses (2015-2019 data from Macon, GA) to determine the modeled meteorological conditions using the procedure described in the Workbook.

First, Washington County Power used the Macon data to develop a set of stability class and wind speed conditions. A joint frequency of occurrence of wind speed, wind direction and atmospheric stability class was then developed for the four, six-hour time periods of the day (Hours 1-6, 7-12, 13-18, and 19-24). Transport to each of the 4 selected sensitive receptors is dependent on different wind directions. Per the Workbook, the worst-case dispersion condition is selected such that sum of all frequencies of occurrence of conditions worse than the selected condition totals 1%. Since the primary concern involving these small airports and parks are visibility conditions during daytime hours, Washington County Power reviewed the frequency of occurrence of meteorological conditions during the daytime time periods (Hours 7-12, and 13-18). As such, the worst-case meteorological conditions utilized in VISCREEN analysis for each area were as follow:

- ► Sandersville/Kaolin Airport – D stability, 8 m/s wind speed
- ► Hamburg State Park – C stability, 4 m/s wind speed
- ► Baldwin State Forest – D stability, 6 m/s wind speed
- ► Baldwin County Airport – B stability, 3 m/s wind speed

Detailed spreadsheets showing how these conditions were determined are included as part of the electronic modeling file submittal.

5.6.5 VISCREEN Analysis Results

The results of the Level 2 VISCREEN analysis are summarized in Table 5-10 through Table 5-13, which present the information shown below:

- ► **Background**: the background against which the plume is viewed (either sky or terrain)
- ► **Theta**: the sun elevation angle above the horizon (0 degrees is when the sun is on the horizon in front of the observer, 90 degrees is directly overhead and 180 degrees is when the sun is on the horizon behind the observer.
  - Forward Scattering Case leading to the brightest plume, when the sun is in front of the observer, 10 degrees above the horizon (Theta = 10 degrees);
  - Backward Scattering Case leading to the darkest plume, when the sun is behind the observer, 40 degrees above the horizon (Theta = 140 degrees).
- ► **Azimuth**: the angle between the line of sight and the line connecting the source and observer (an azimuth angle of zero implies that the observer is looking directly toward the source)
- ► **Distance**: the distance from the source to the point at which the observer's line of sight intersects the plume
- ► **Alpha**: the angle between the light of sight and the plume centerline
- ► **ΔE Critical**: the perceptibility screening threshold (2.0) [40]

[40] In some cases, VISCREEN changes critical delta E and contrast depending on input parameters, however, compliance was determined based on the default screening levels.

- **ΔE Plume**: the maximum modeled plume perceptibility
- **Contrast Critical**: the contrast screening threshold (0.05)
- **Contrast Plume**: the maximum modeled plume contrast

Table 5-10. Level 2 VISCREEN Results – Sandersville/Kaolin Airport

Background	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10	122	21	46	2.0	0.734	0.05	-0.001
SKY	140	122	21	46	2.0	0.247	0.05	-0.004
TERRAIN	10	84	18	84	2.0	0.246	0.05	0.003
TERRAIN	140	84	18	84	2.0	0.071	0.05	0.002

Table 5-11. Level 2 VISCREEN Results – Hamburg State Park

Background	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10	84	20.5	84	2.0	0.272	0.05	0.000
SKY	140	84	20.5	84	2.0	0.093	0.05	-0.001
TERRAIN	10	84	20.5	84	2.0	0.079	0.05	0.001
TERRAIN	140	84	20.5	84	2.0	0.023	0.05	0.001

Table 5-12. Level 2 VISCREEN Results – Baldwin State Forest

Background	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10	118	24.5	51	2.0	0.746	0.05	-0.001
SKY	140	118	24.5	51	2.0	0.250	0.05	-0.004
TERRAIN	10	84	21.5	84	2.0	0.226	0.05	0.003
TERRAIN	140	84	21.5	84	2.0	0.067	0.05	0.002

Table 5-13. Level 2 VISCREEN Results – Baldwin County Airport

Background	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10	84	24	84	2.0	0.088	0.05	0.000
SKY	140	84	24	84	2.0	0.030	0.05	0.000
TERRAIN	10	84	24	84	2.0	0.022	0.05	0.000
TERRAIN	140	84	24	84	2.0	0.007	0.05	0.000

As shown above, the Level 2 VISCREEN results indicate that the proposed project will not cause any significant visible plume impacts at the surrounding sensitive receptors. The electronic output and summary files from each of the VISCREEN runs is included as part of the electronic modeling file submittal.

5.7 Toxic Impact Assessment

EPD regulates the emissions of toxic air pollutants (TAP) through a program approved under the provisions of GRAQC Rule 391-3-1-.02(2)(a)3(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the EPD's review of toxic air pollutant emissions as part of air permit reviews are contained in EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (TAP Guideline)*.[41] The Guideline has established the Allowable Ambient Concentration (AAC) and Minimum Emission Rate (MER) for each TAP, which are included in Appendix A of the Guideline.

According to the *TAP Guideline*, dispersion modeling should be completed for each potentially toxic pollutant having quantifiable emissions above the MER for that pollutant.

As described in the Volume I report, the Facility developed a maximum annual emission rate for all listed TAPs for which MER thresholds have been established. Table 5-14 summarizes the facility-wide emission rates for each TAP in comparison to their respective MERs.

[41] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May 2017.

Table 5-14. Facility-Wide TAP Emissions and Respective MER

Pollutant	CAS No.	Total Potential Emissions (tpy)	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER? (Y/N)
1,3-Butadiene	106990	3.48E-02	69.68	7.30	Y
2-Methylnaphthalene	91576	2.08E-06	4.16E-03	--	--
3-Methylcholanthrene	56495	1.56E-07	3.12E-04	--	--
7,12-Dimethylbenz(a)anthracene	57976	1.39E-06	2.78E-03	--	--
Acenaphthene	83329	5.73E-06	1.15E-02	--	--
Acenaphthylene	208968	1.72E-06	3.44E-03	--	--
Acetaldehyde	75070	0.42	849.37	1.11E+03	N
Acrolein	107028	6.79E-02	135.83	4.87	Y
Anthracene	120127	2.27E-06	4.53E-03	--	--
Arsenic	7440382	2.08E-02	41.61	5.67E-02	Y
Benz(a)anthracene	56553	2.01E-06	4.01E-03	--	--
Benzene	71432	0.23	467.24	31.63	Y
Benzo(a)pyrene	50328	3.11E-07	6.22E-04	--	--
Benzo(b)fluoranthene	205992	2.65E-07	5.30E-04	--	--
Benzo(g,h,i)perylene	191242	6.42E-07	1.28E-03	--	--
Benzo(k)fluoranthene	207089	3.27E-07	6.54E-04	--	--
Beryllium	7440417	5.87E-04	1.17	0.97	Y
Cadmium	7440439	9.17E-03	18.33	1.35	Y
Chromium	7440473	2.09E-02	41.82	58.40	N
Chrysene	218019	5.45E-07	1.09E-03	--	--
Cobalt	7440484	7.29E-06	1.46E-02	11.68	N
Dibenzo(a,h)anthracene	53703	7.46E-07	1.49E-03	--	--
Dichlorobenzene	25321226	1.04E-04	0.21	--	--
Ethylbenzene	100414	0.34	682.21	2.43E+05	N
Fluoranthene	206440	8.64E-06	1.73E-02	--	--
Fluorene	86737	3.24E-05	6.48E-02	--	--
Formaldehyde	50000	8.06	1.61E+04	267.00	Y
Hexane	110543	0.16	312.79	1.70E+05	N
Indeno(1,2,3-cd)pyrene	193395	5.69E-07	1.14E-03	--	--
Lead	7439921	2.65E-02	53.01	5.84	Y
Manganese	7439965	1.49	2.99E+03	12.17	Y
Mercury	7439976	2.29E-03	4.58	73.00	N
Naphthalene	91203	8.04E-02	160.76	729.99	N
Nickel	7440020	8.88E-03	17.75	38.64	N
Pentane	109660	0.23	451.05	3.42E+05	N
Propane	74986	0.14	277.57	2.09E+05	N
Phenanthrene	85018	3.38E-05	6.77E-02	--	--
Pyrene	129000	5.70E-06	1.14E-02	--	--
Propylene oxide	75569	0.31	614.57	656.99	N
Selenium	7782492	4.73E-02	94.50	23.36	Y
Toluene	108883	1.39	2.79E+03	1.22E+06	N
Xylene	1330207	3.96E-02	79.29	2.43E+04	N
Sulfuric Acid	7664939	5.02	1.00E+04	116.81	Y

Based on the comparison of TAPs emitted by the facility to the MERs, multiple pollutants required a direct modeling evaluation in comparison to the AACs, as published by the Georgia EPD as part of the current version of Appendix A (revised October 2018) to the *TAP Guideline*. The modeling assessment was done using the EPA AERMOD model (version 19191) with the turbine's parameters at 100% load. Modeled source parameters for the toxics modeling assessment can be found in Appendix D of this report.

A summary of the air toxics modeling results, with use of AERMOD, is provided in the following table. Modeling files for the air toxics modeling assessment, can be found in Appendix E.

Table 5-15. Summary of Toxics Modeling Analysis Results

Pollutant	CAS No.	Year	Maximum 1-Hour Impact (μg/m³)	Maximum 15-Min Impact[1] (μg/m³)	15-min AAC2 (μg/m³)	Is MGLC >15-min AAC? (Y/N)	Maximum 24-hr Impact (μg/m³)	24-hr AAC2 (μg/m³)	Is MGLC > 24-hr AAC? (Y/N)	Maximum Annual Impact (μg/m³)	Annual AAC (μg/m³)	Is MGLC > Annual AAC? (Y/N)
1,3-Butadiene	106990	Max	7.58E-03	1.00E-02	1,100	N	N/A	N/A	N/A	6.00E-05	3.00E-02	N
Acrolein	107028	Max	2.82E-03	3.72E-03	23	N	N/A	N/A	N/A	2.00E-05	2.00E-02	N
Arsenic	7440382	Max	5.21E-03	6.88E-03	0.2	N	N/A	N/A	N/A	4.00E-05	2.33E-04	N
Benzene	71432	Max	1.86E-01	2.45E-01	1,600	N	N/A	N/A	N/A	1.11E-02	0.13	N
Beryllium	7440417	Max	1.50E-04	1.98E-04	0.5	N	N/A	N/A	N/A	0.00E+00	4.00E-03	N
Cadmium	7440439	Max	2.28E-03	3.01E-03	30	N	N/A	N/A	N/A	4.00E-05	5.56E-03	N
Formaldehyde	50000	Max	3.15E-01	0	245	N	N/A	N/A	N/A	3.81E-03	1.10	N
Lead	7439921	Max	N/A	N/A	N/A	N/A	9.20E-04	0.12	N	N/A	N/A	N/A
Manganese	7439965	Max	3.74E-01	4.93E-01	500	N	N/A	N/A	N/A	2.75E-03	5.00E-02	N
Selenium	7782492	Max	N/A	N/A	N/A	N/A	1.64E-03	0.48	N	N/A	N/A	N/A
Sulfuric Acid	7664939	Max	0.44	0.57	300	N	0.18	2.40	N	N/A	N/A	N/A

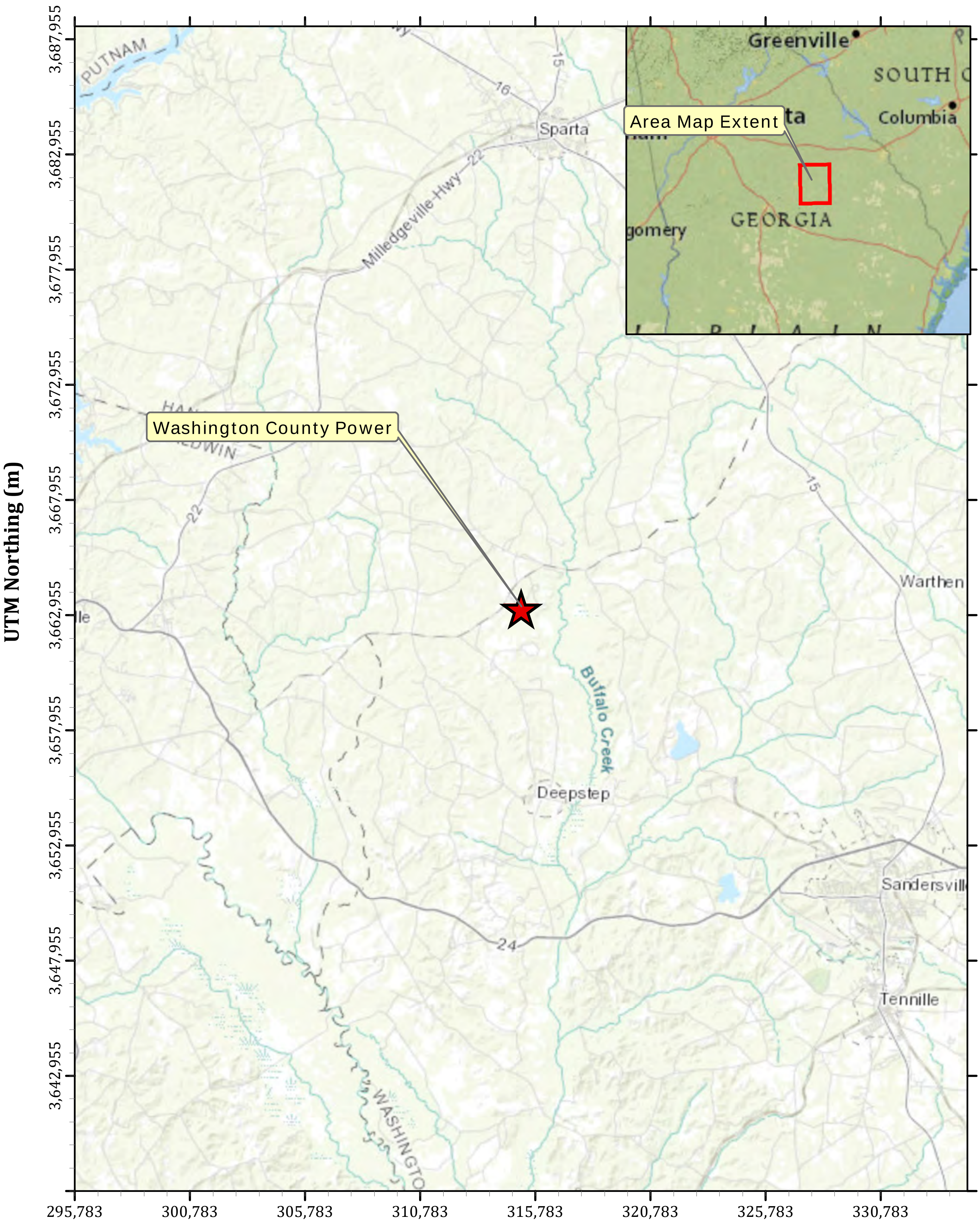
1. 15-minute impacts equal the 1-hour impact times a factor of 1.32 per the Guideline, page 12.

The maximum 15-min average impact was calculated by adjusting the maximum modeled 1-hour impact using the multiplying factor in the *TAP Guideline* (factor of 1.32). As shown in Table 5-15, the impacts of toxic air pollutants evaluated from the facility's operations are below all applicable AACs.

APPENDIX A. FIGURES

Appendix A-1. Area Map

Washington County Power, LLC - Sandersville, Washington County , Georgia

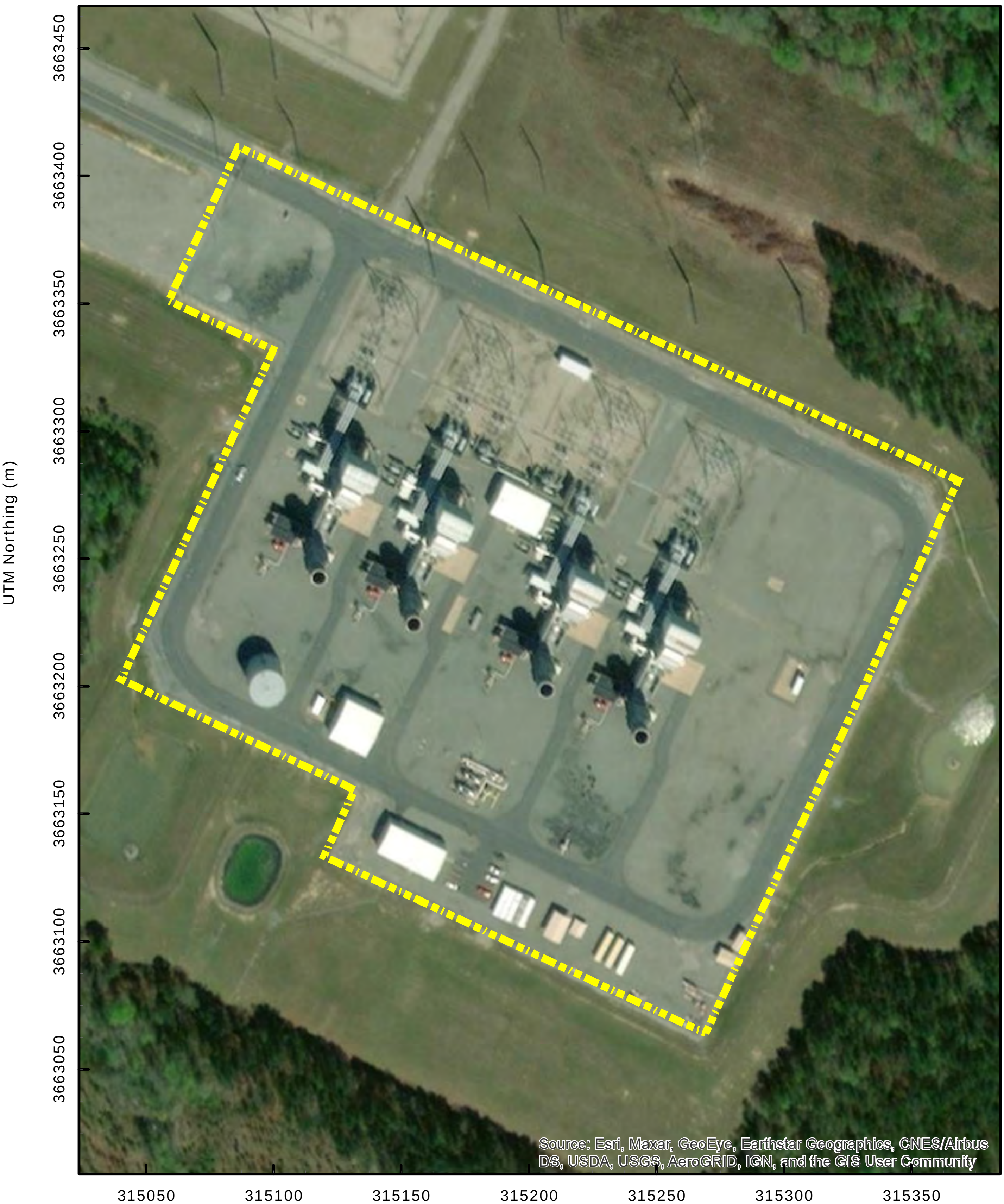


UTM Easting (m)

All Coordinates shown in UTM Coordinates,
Zone 17, NAD 83 Datum

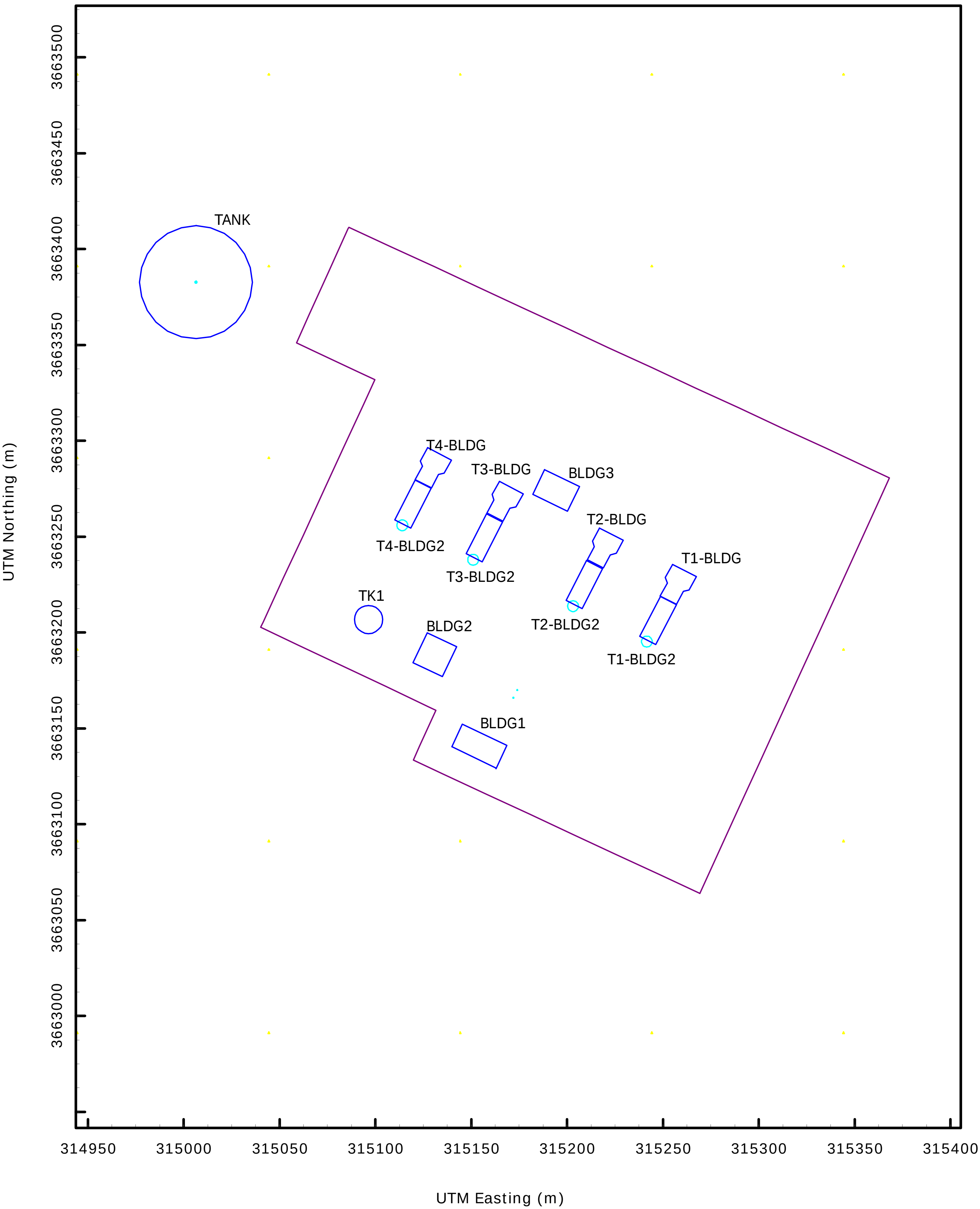
Trinity Consultants

Figure A-2. Boundary Receptors
Washington County Power, LLC



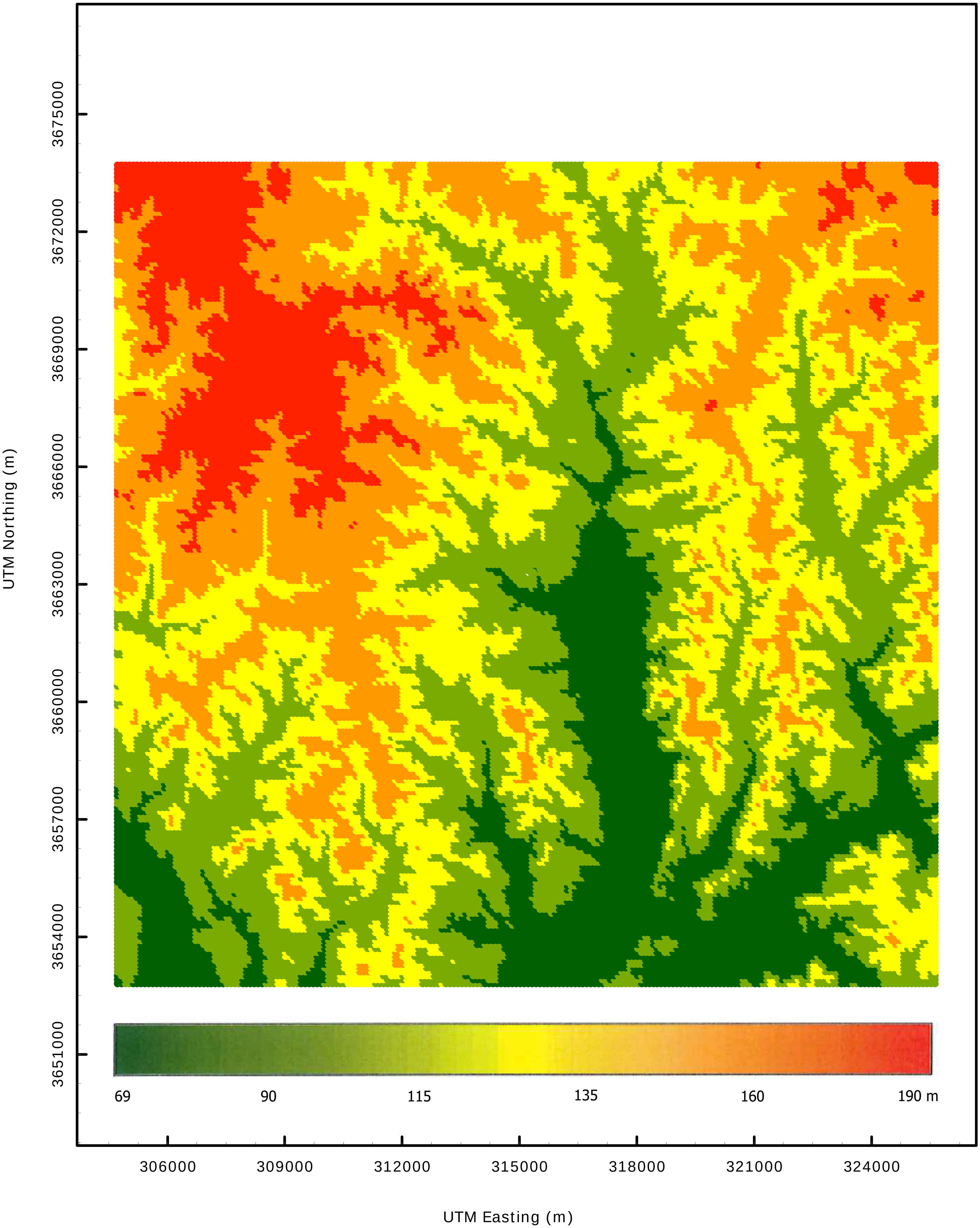
UTM Easting (m)
All coordinates in UTM NAD83, Zone 17

Figure A-3. Facility Layout - Buildings & Sources
Washington County Power, LLC



All coordinates in UTM NAD83, Zone 17

Figure A-4. 100 Meter-Spaced Receptor Grid
Washington County Power, LLC



All coordinates in UTM NAD83, Zone 17

Figure A-5. Receptor Grid NO2 1-Hr (Fuel Oil)
Washington County Power, LLC

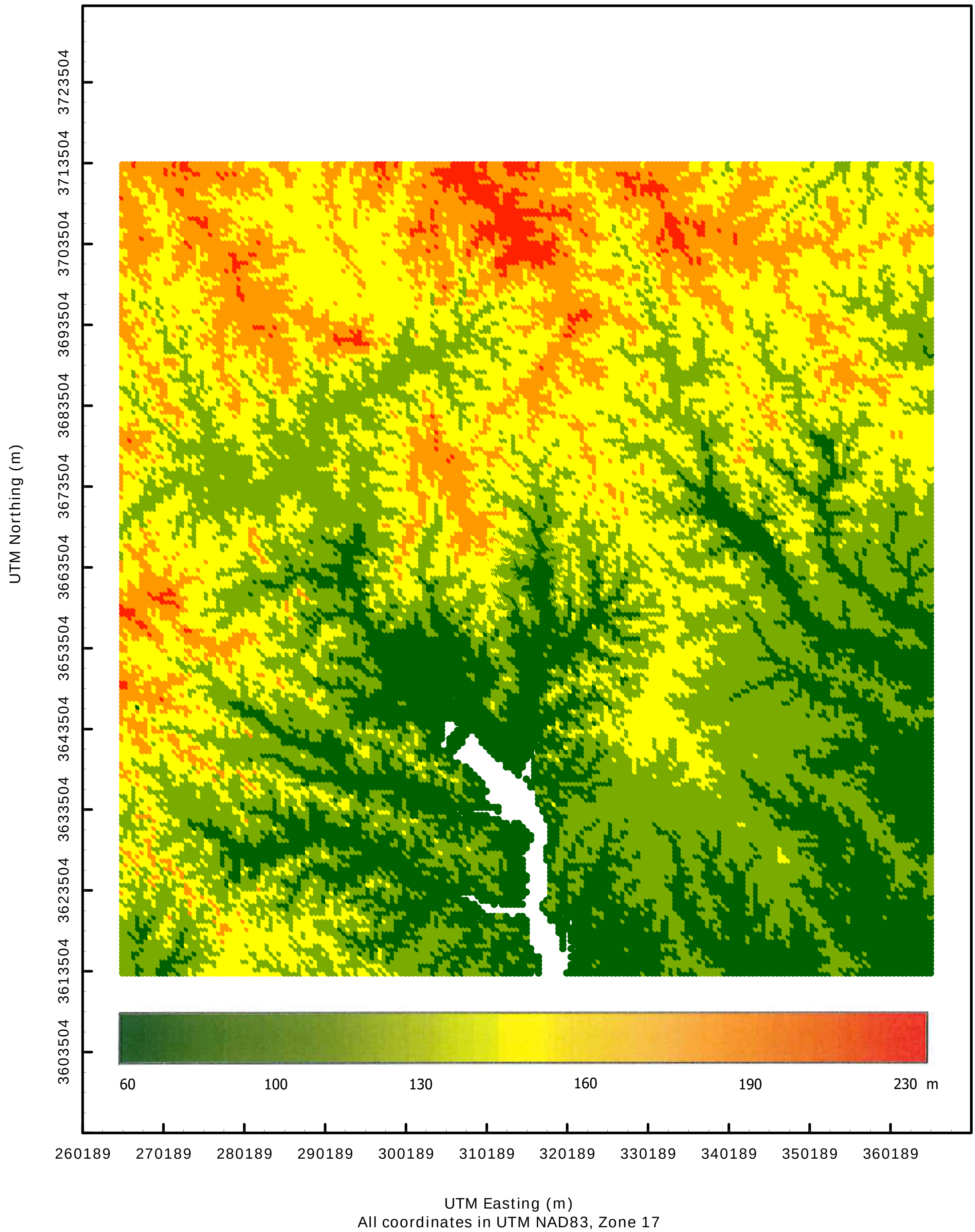
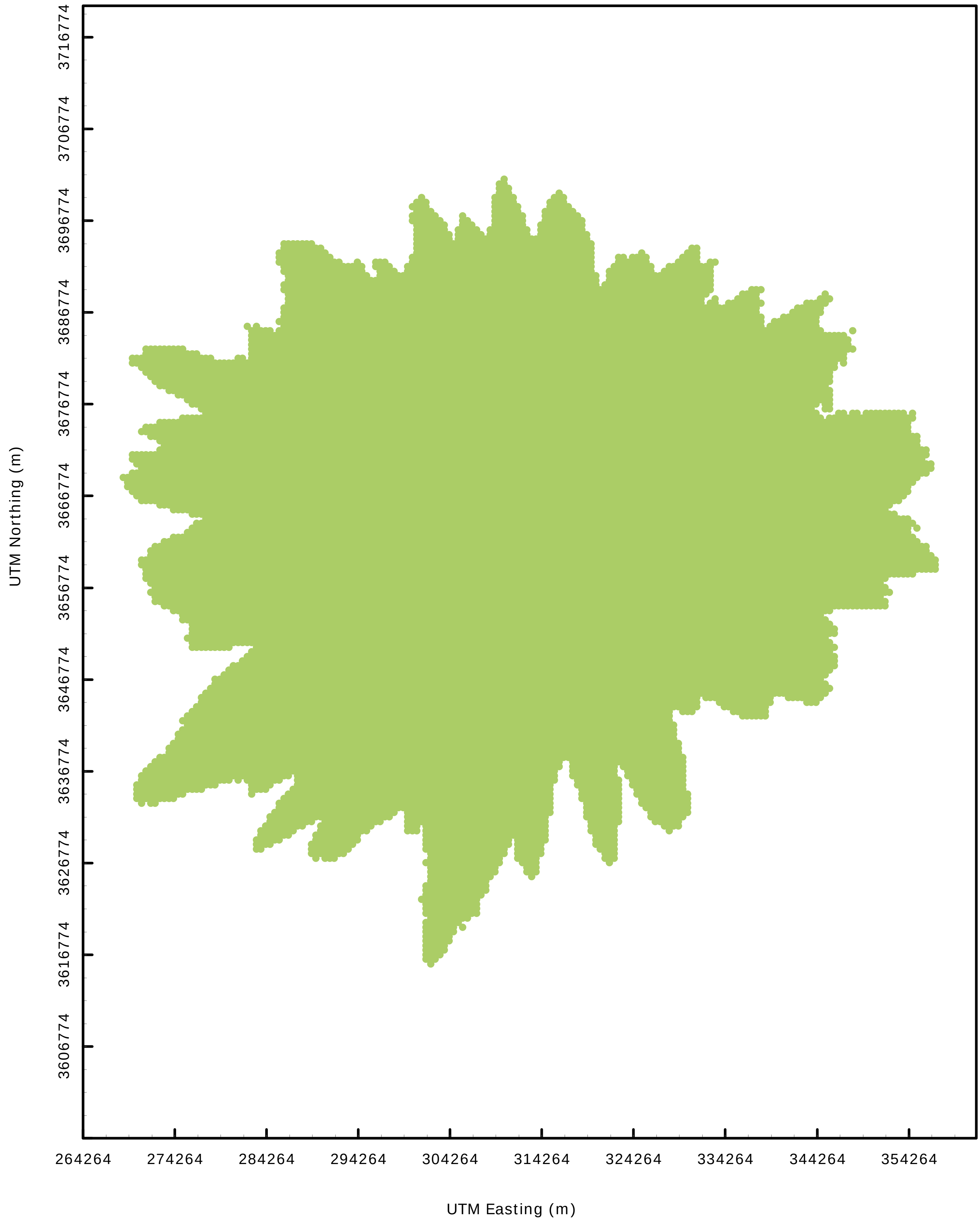


Figure A-6. NO2 1-Hr Significant Receptor Gruid (Fuel Oil)
Washington County Power, LLC



All coordinates in UTM NAD83, Zone 17

Figure A-7. NO2 1-Hr Significant Receptor Grid (Natural Gas)
Washington County Power, LLC

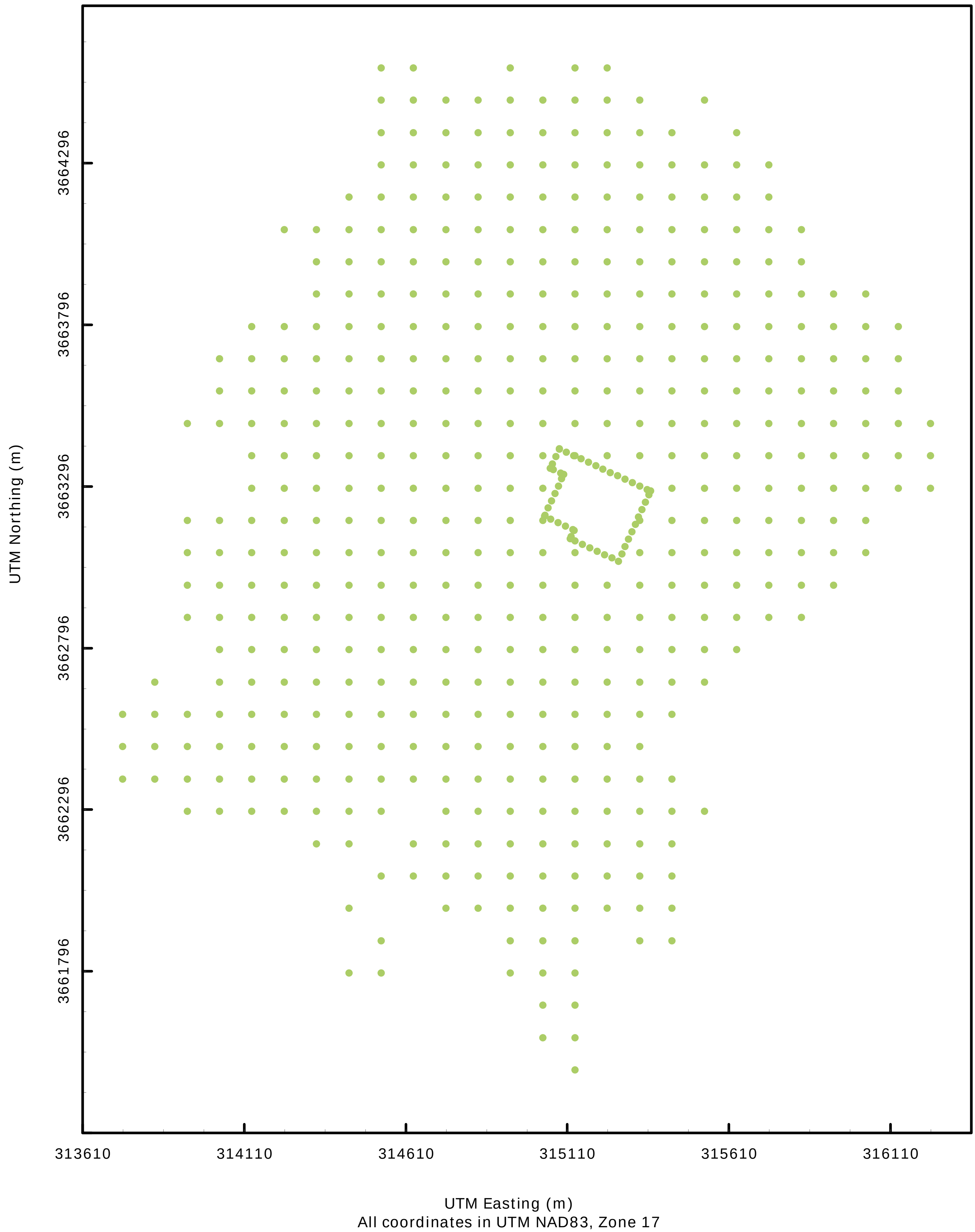


Figure A-8. NO2 Annual Significant Receptor Grid
Washington County Power, LLC

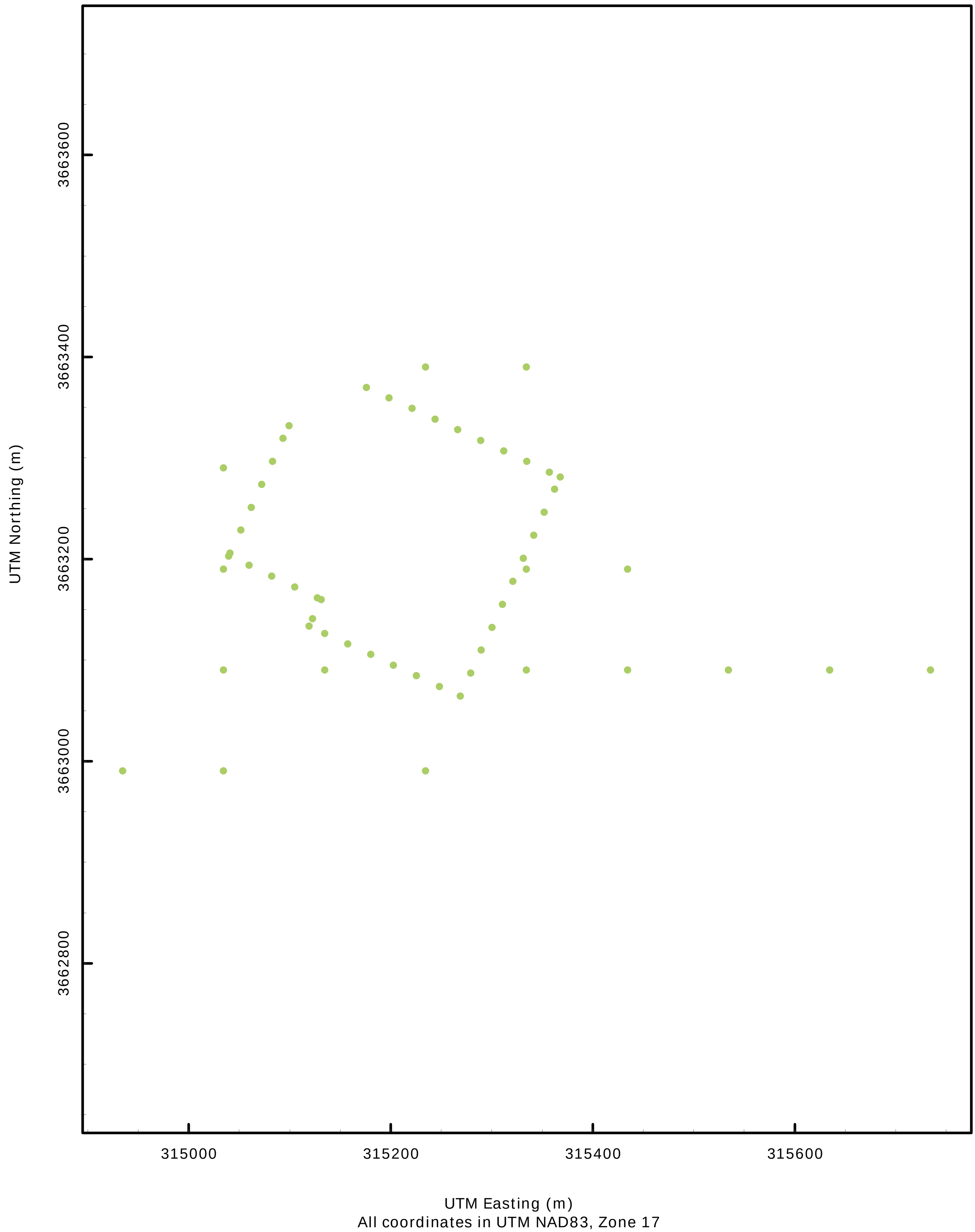
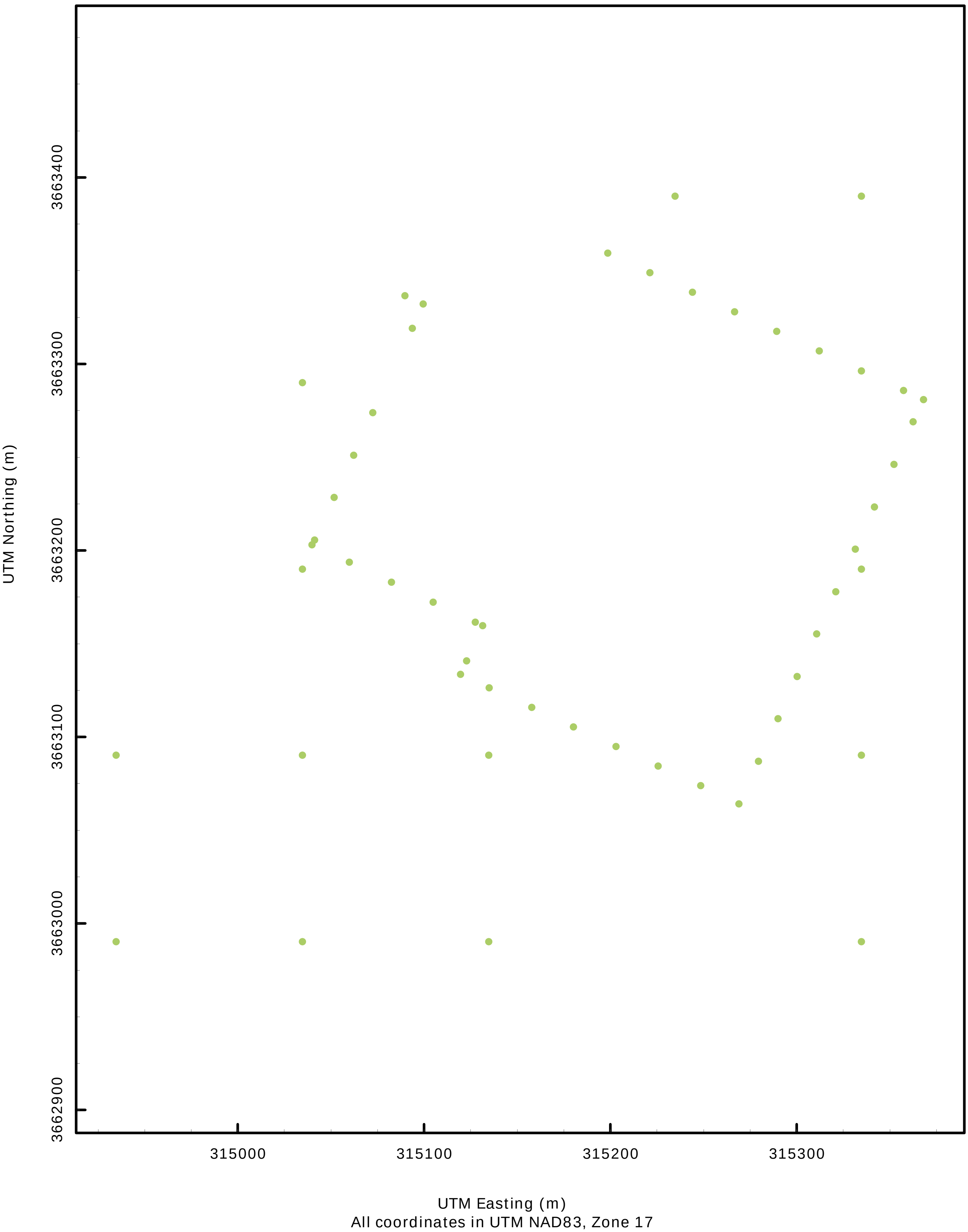


Figure A-9. PM2.5 Significant Receptor Grid
Washington County Power, LLC



Note: Receptors reprefent PM2.5 Increment significant receptors and NAAQS significant receptors

APPENDIX B. CLASS I NOTIFICATION DOCUMENTATION

Trinity Consultants
3495 Piedmont Rd, Bldg 10, Ste 905, Atlanta, GA 30305 / P 678.441.9977 / F 678.441.9978 / **trinityconsultants.com**

February 16, 2021

Mr. Chuck Sams
USDA Forest Service (FS)
Regional Air Program Manager
US Forest Service
1720 Peachtree Rd.
Atlanta, GA 30309

RE: Washington County Power, LLC - Sandersville, GA
Fuel Oil Conversion Project
Project in Reference to FS Class I Area

Dear Mr. Sams,

Trinity Consultants (Trinity) is submitting this letter to your attention on behalf of our client Washington County Power, LLC (WCP) located in Sandersville, Georgia (Washington County). WCP is proposing to modify the four existing simple cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil. The proposed project will require a Prevention of Significant Deterioration (PSD) construction permit as emissions from the proposed project are anticipated to exceed the PSD significant emission rate (SER) threshold for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), Volatile Organic Compounds (VOC), carbon monoxide (CO) and GHGs (CO_2e).

The purpose of this letter is to provide the Federal Land Manager (FLM) with preliminary information on the proposed project and to request concurrence from the FLM on the findings presented.

Q/D SCREENING ANALYSIS

A Q/D screening analysis was performed in a manner consistent with the approach discussed in the most recent Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance document (FLAG 2010), which compares the ratio of visibility affecting pollutant emissions to the distance from the Class I area (i.e., referenced herein as the FLAG 2010 Approach).[1] "Q" is the sum of the annual NO_X, PM_{10}, SO_2, and sulfuric acid mist (H_2SO_4) emissions, in tons per year (tpy)[2] and "D" is the distance, in kilometers (km), from the proposed facility to the corresponding Class I area. The total emissions for this project will include emissions from all point sources to be modified as part of this project.

A summary of the visibility-affecting pollutant (VAP) emissions resulting from the proposed project are shown in Table 1 using the FLAG 2010 Approach. Emissions shown below are the current estimates of increases in the maximum 24-hr short term emission rates of the listed pollutants for this project, and the corresponding tpy increases. NOx and PM emissions are based on the proposed BACT. SO_2 and H_2SO_4

[1] Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised 2010, *October 7, 2010*.
[2] It is specified within the Flag 2010 Report that "Q" be calculated as the sum of the worst-case 24-hour emissions converted to an annual basis.

emissions are small due to use of ultra-low sulfur diesel or natural gas. Project data regarding emissions may change, and any necessary updates will be provided to the FLM as necessary.

Table 1. Summary of Visibility-Affecting Pollutant Emissions

Pollutant	Facility-Wide Maximum 24-hr Emissions Increase (lb/hr)	FLAG 2010 Approach Annual Emissions[2] (tpy)
NO_X	139.48	610.94
Direct Particulate[1]	39.27	172.00
SO_2	2.10	9.19
H_2SO_4	0.97	4.26
Sum of Emissions (tpy)		1,993.25

1. Direct particulate includes all filterable and condensable PM_{10}.
2. FLAG 2010 Approach: Q = Sum of allowable emissions * 8760/3500 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the source during limited source operation.

The Cohutta Wilderness, Shining Rock Wilderness and Joyce Kilmer-Slickrock Wilderness are Class I Areas within 300 km of the proposed project site that is indicated as under your jurisdiction. [3]

Table 2. Summary of the Q/D Assessment

Class I Area	Responsible FLM	Minimum Distance from Site (km)	Sum of Annualized VAP Emissions - Q (tpy)	Flag 2010 Approach Q/D
Cohutta Wilderness	FS	244	1,993.25	8.18
Shining Rock Wilderness	FS	248	1,993.25	8.03
Joyce Kilmer-Slickrock Wilderness	FS	264	1,993.25	7.54

Table 2 shows the results of the Q/D screening analysis for the FLAG 2010 Approach. As shown in Table 2, the project has a Q/D well below ten. This suggests that the proposed project will have no adverse impacts to any AQRVs at the Cohutta Wilderness, Shining Rock Wilderness or Joyce Kilmer-Slickrock Wilderness. Therefore, WCP plans no AQRV analyses for the proposed project. Based on Table 2, WCP requests that the FS provide written concurrence of this finding of no impact.

~~~~~~~~~~~~~~~~~~~~~~~~~~

[3] Notifications regarding other Class I areas within 300 km of the project location was made under separate cover.
~~~~~~~~~~~~~~~~~~~~~~~~~~

WCP greatly appreciates your feedback on this conclusion regarding no presumptive impacts to AQRVs at Class I areas under your management. Please feel free to contact me at 404-751-0228 with any questions that you have.

Sincerely,

TRINITY CONSULTANTS

Justin Fickas
Managing Consultant

Trinity Consultants
3495 Piedmont Rd, Bldg 10, Ste 905, Atlanta, GA 30305 / P 678.441.9977 / F 678.441.9978 / trinityconsultants.com

February 16, 2021

Ms. Meredith Bond
United States Department of the Interior
U.S. Fish and Wildlife Service (FWS)
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood , CO 80235-2017

RE: Washington County Power, LLC - Sandersville, GA
Fuel Oil Conversion Project
Project in Reference to FWS Class I Area - Okefenokee Wilderness and Wolf Island Wilderness

Dear Ms. Bond,

Trinity Consultants (Trinity) is submitting this letter to your attention on behalf of our client Washington County Power, LLC (WCP) located in Sandersville, Georgia (Washington County). WCP is proposing to modify the four existing simple cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil. The proposed project will require a Prevention of Significant Deterioration (PSD) construction permit as emissions from the proposed project are anticipated to exceed the PSD significant emission rate (SER) threshold for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), Volatile Organic Compounds (VOC), carbon monoxide (CO) and GHGs (CO_2e).

The purpose of this letter is to provide the Federal Land Manager (FLM) with preliminary information on the proposed project and to request concurrence from the FLM on the findings presented.

Q/D SCREENING ANALYSIS

A Q/D screening analysis was performed in a manner consistent with the approach discussed in the most recent Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance document (FLAG 2010), which compares the ratio of visibility affecting pollutant emissions to the distance from the Class I area (i.e., referenced herein as the FLAG 2010 Approach).[1] "Q" is the sum of the annual NO_X, PM_{10}, SO_2, and sulfuric acid mist (H_2SO_4) emissions, in tons per year (tpy)[2] and "D" is the distance, in kilometers (km), from the proposed facility to the corresponding Class I area. The total emissions for this project will include emissions from all point sources to be modified as part of this project.

A summary of the visibility-affecting pollutant (VAP) emissions resulting from the proposed project are shown in Table 1 using the FLAG 2010 Approach. Emissions shown below are the current estimates of increases in the maximum 24-hr short term emission rates of the listed pollutants for this project, and the corresponding tpy increases. NOx and PM emissions are based on the proposed BACT. SO_2 and H_2SO_4

[1] Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised 2010, *October 7, 2010*.
[2] It is specified within the Flag 2010 Report that "Q" be calculated as the sum of the worst-case 24-hour emissions converted to an annual basis.

emissions are small due to use of ultra-low sulfur diesel or natural gas. Project data regarding emissions may change, and any necessary updates will be provided to the FLM as necessary.

Table 1. Summary of Visibility-Affecting Pollutant Emissions

Pollutant	Facility-Wide Maximum 24-hr Emissions Increase (lb/hr)	FLAG 2010 Approach Annual Emissions[2] (tpy)
NO_X	139.48	610.94
Direct Particulate[1]	39.27	172.00
SO_2	2.10	9.19
H_2SO_4	0.97	4.26
Sum of Emissions (tpy)		1,993.25

1. Direct particulate includes all filterable and condensable PM_{10}.
2. FLAG 2010 Approach: Q = Sum of allowable emissions * 8760/3500 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the source during limited source operation.

The Okefenokee Wilderness and Wolf Island Wilderness are the Class I Areas within 300 km of the proposed project site that is indicated as under your jurisdiction. [3]

Table 2. Summary of the Q/D Assessment

Class I Area	Responsible FLM	Minimum Distance from Site (km)	Sum of Annualized VAP Emissions - Q (tpy)	Flag 2010 Approach Q/D
Okefenokee Wilderness	FWS	234	1,993.25	8.51
Wolf Island Wilderness	FWS	247	1,993.25	8.06
Wolf Island Wilderness	FWS	253	1,993.25	7.87

Table 2 shows the results of the Q/D screening analysis for the FLAG 2010 Approach. As shown in Table 2, the project has a Q/D well below ten. This suggests that the proposed project will have no adverse impacts to any AQRVs at the Great Smoky Mountains. Therefore, WCP plans no AQRV analyses for the proposed project. Based on Table 2, WCP requests that the FWS provide written concurrence of this finding of no impact.

~~~~~~~~~~~~~~~~~~~~~~~~~~

[3] Notifications regarding other Class I areas within 300 km of the project location was made under separate cover.
~~~~~~~~~~~~~~~~~~~~~~~~~~

WCP greatly appreciates your feedback on this conclusion regarding no presumptive impacts to AQRVs at Class I areas under your management. Please feel free to contact me at 404-751-0228 with any questions that you have.

Sincerely,

TRINITY CONSULTANTS

Justin Fickas
Managing Consultant

Trinity Consultants
3495 Piedmont Rd, Bldg 10, Ste 905, Atlanta, GA 30305 / P 678.441.9977 / F 678.441.9978 / **trinityconsultants.com**

February 16, 2021

Ms. Carol McCoy
Division Chief
National Park Service (NPS)
Air Resources Division
PO Box 25287
Denver, Colorado 80225-0287

RE: Washington County Power, LLC - Sandersville, GA
Fuel Oil Conversion Project
Project in Reference to NPS Class I Area - Great Smoky Mountains

Dear Ms. McCoy,

Trinity Consultants (Trinity) is submitting this letter to your attention on behalf of our client Washington County Power, LLC (WCP) located in Sandersville, Georgia (Washington County). WCP is proposing to modify the four existing simple cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil. The proposed project will require a Prevention of Significant Deterioration (PSD) construction permit as emissions from the proposed project are anticipated to exceed the PSD significant emission rate (SER) threshold for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), Volatile Organic Compounds (VOC), carbon monoxide (CO) and GHGs (CO_2e).

The purpose of this letter is to provide the Federal Land Manager (FLM) with preliminary information on the proposed project and to request concurrence from the FLM on the findings presented.

Q/D SCREENING ANALYSIS

A Q/D screening analysis was performed in a manner consistent with the approach discussed in the most recent Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance document (FLAG 2010), which compares the ratio of visibility affecting pollutant emissions to the distance from the Class I area (i.e., referenced herein as the FLAG 2010 Approach).[1] "Q" is the sum of the annual NO_X, PM_{10}, SO_2, and sulfuric acid mist (H_2SO_4) emissions, in tons per year (tpy)[2] and "D" is the distance, in kilometers (km), from the proposed facility to the corresponding Class I area. The total emissions for this project will include emissions from all point sources to be modified as part of this project.

A summary of the visibility-affecting pollutant (VAP) emissions resulting from the proposed project are shown in Table 1 using the FLAG 2010 Approach. Emissions shown below are the current estimates of increases in the maximum 24-hr short term emission rates of the listed pollutants for this project, and the corresponding tpy increases. NOx and PM emissions are based on the proposed BACT. SO_2 and H_2SO_4

[1] Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised 2010, *October 7, 2010*.
[2] It is specified within the Flag 2010 Report that "Q" be calculated as the sum of the worst-case 24-hour emissions converted to an annual basis.

emissions are small due to use of ultra-low sulfur diesel or natural gas. Project data regarding emissions may change, and any necessary updates will be provided to the FLM as necessary.

Table 1. Summary of Visibility-Affecting Pollutant Emissions

Pollutant	Facility-Wide Maximum 24-hr Emissions Increase (lb/hr)	FLAG 2010 Approach Annual Emissions[2] (tpy)
NO_X	139.48	610.94
Direct Particulate[1]	39.27	172.00
SO_2	2.10	9.19
H_2SO_4	0.97	4.26
Sum of Emissions (tpy)		1,993.25

1. Direct particulate includes all filterable and condensable PM_{10}.
2. FLAG 2010 Approach: Q = Sum of allowable emissions * 8760/3500 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the source during limited source operation.

The Great Smoky Mountains is the only Class I Areas within 300 km of the proposed project site that is indicated as under your jurisdiction. [3]

Table 2. Summary of the Q/D Assessment

Class I Area	Responsible FLM	Minimum Distance from Site (km)	Sum of Annualized VAP Emissions - Q (tpy)	Flag 2010 Approach Q/D
Great Smoky Mountains	NPS	263	1,993.25	7.57

Table 2 shows the results of the Q/D screening analysis for the FLAG 2010 Approach. As shown in Table 2, the project has a Q/D well below ten. This suggests that the proposed project will have no adverse impacts to any AQRVs at the Great Smoky Mountains. Therefore, WCP plans no AQRV analyses for the proposed project. Based on Table 2, WCP requests that the NPS provide written concurrence of this finding of no impact.

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[3] Notifications regarding other Class I areas within 300 km of the project location was made under separate cover.
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WCP greatly appreciates your feedback on this conclusion regarding no presumptive impacts to AQRVs at Class I areas under your management. Please feel free to contact me at 404-751-0228 with any questions that you have.

Sincerely,

TRINITY CONSULTANTS

Justin Fickas
Managing Consultant

APPENDIX C. MODELING PROTOCOL AND EPD RESPONSE

Trinity Consultants
3495 Piedmont Rd, Bldg 10, Ste 905, Atlanta, GA 30305 / P 678.441.9977 / F 678.441.9978 / **trinityconsultants.com**

October 29, 2020

Mr. Byeong-Uk Kim
Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30354
Byeong.Kim@dnr.ga.gov

RE: Washington County Power, LLC, Sandersville, GA Site Modeling Protocol for PSD Application – Fuel Oil Conversion Project

Dear Mr. Kim:

Washington County Power, LLC ("WCP") owns and operates a natural gas-fired simple-cycle power generation facility northwest of Sandersville, Georgia (the "Facility"). The Facility consists of four General Electric (GE) Frame 7A combustion turbines, with the capacity to generate approximately 680 MW, along with other ancillary facility equipment including two fuel gas heaters, an emergency fire pump engine, and an auxiliary generator engine. The facility is proposing to modify the four existing simple cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil.

The proposed project will require a Prevention of Significant Deterioration (PSD) permit as a major modification to an existing major source.[1] Projected-related emissions increases are anticipated to exceed the PSD significant emission rate (SER) thresholds for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_x), Volatile Organic Compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e).[2]

A dispersion modeling protocol has been prepared following the policy and guidance of the Georgia Environmental Protection Division (GAEPD). Trinity Consultants (Trinity), on behalf of WCP, has prepared this dispersion modeling protocol describing the proposed methodologies and data resources to be used for the modeling compliance demonstration. This protocol includes a brief description of the proposed project, an overview of the required PSD and State modeling analyses, and a detailed description of the methodology proposed to be used in the modeling analyses. The analyses include evaluation and consideration of National Ambient Air Quality Standards (NAAQS), PSD Increment, additional impacts analyses, visibility and non-air quality impacts, ambient impact assessment of toxic air pollutant (TAP) emissions, as well as consideration of impacts to Class I Areas.

[1] The Facility is currently a PSD minor source, with PSD avoidance limitations (e.g. Permit Condition No. 2.1.1) limiting facility wide emissions of NOx to less than 250 tpy. The facility is not classified as one of the 28 named source categories, and is subject to a 250 tpy PSD major source threshold.

[2] CO_2e is carbon dioxide equivalents calculated as the sum of the six well-mixed GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) with applicable global warming potentials per 40 CFR 98 applied.

PROJECT DESCRIPTION

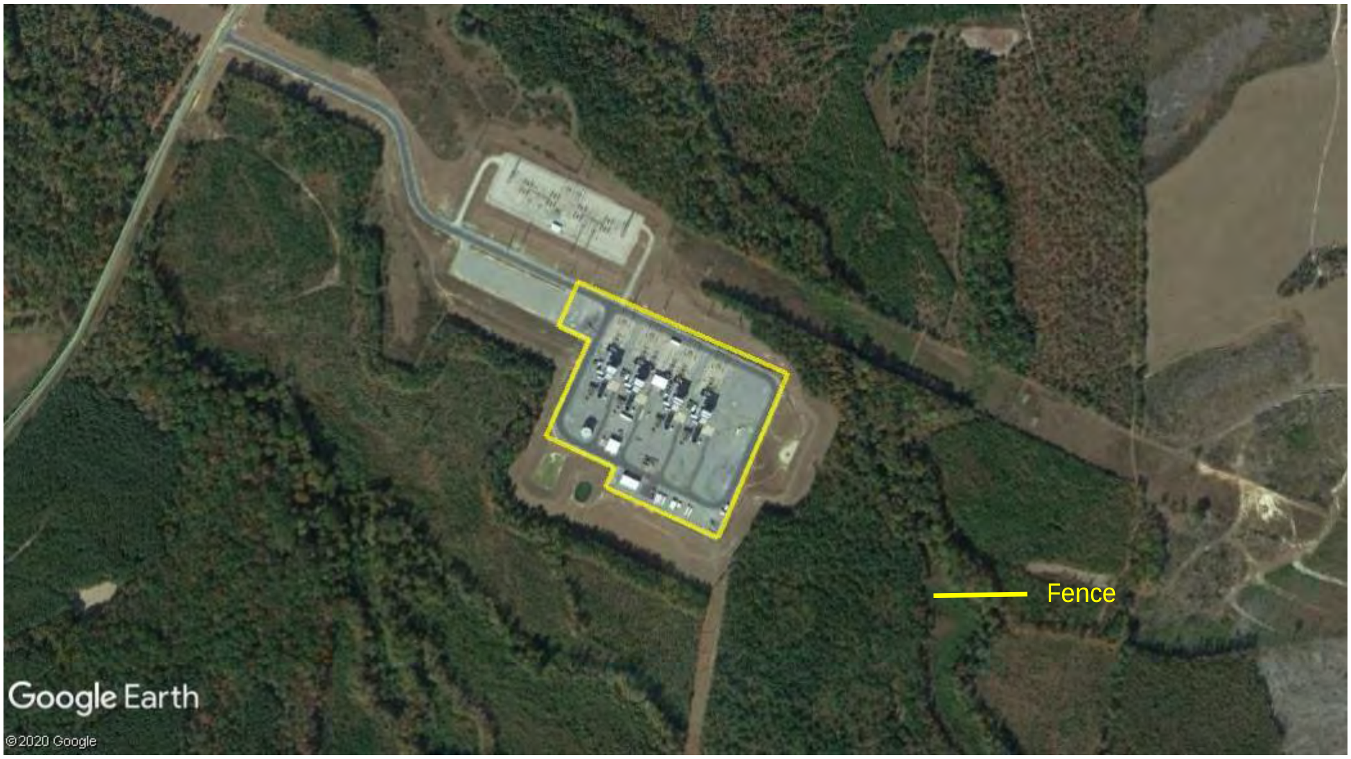
Washington County Power, LLC ("WCP") owns and operates a natural gas-fired simple-cycle power generation facility northwest of Sandersville, Georgia (the "Facility"). The Facility consists of four General Electric (GE) Frame 7A combustion turbines, with the capacity to generate approximately 680 MW, along with other ancillary facility equipment including two fuel gas heaters, an emergency fire pump engine, and an auxiliary generator engine. The facility is proposing to modify the four existing simple cycle turbines to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,000 hr/yr per turbine on natural gas, and 500 hr/yr on fuel oil.

Figure 1 provides a map of the area surrounding the existing proposed project location. The approximate central Universal Transverse Mercator (UTM) coordinates of the Facility (centered around the emissions sources) are 315.183 kilometers (km) East and 3,663.253 km North in Zone 17 (NAD 83). The area surrounding the facility is predominantly rural.

Figure 1. WCP Facility Area Map

Figure 2 depicts the fence line boundary of the Facility. The boundary area indicated below is completely fenced.

Figure 2. WCP Facility Ambient Boundary



PSD APPLICABILITY

Part C of Title I of the Clean Air Act, 42 U.S.C. §§7470-7492, is the statutory basis for the PSD program. The Environmental Protection Agency (EPA) has codified PSD definitions, applicability, and requirements in 40 CFR Part 52.21. PSD is addressed and implemented through Georgia Rule 391-3-1-.02(7). PSD is one component of the New Source Review (NSR) permitting program applicable in areas that are designated in attainment of the NAAQS. Washington County, where the facility is located, is currently designated as unclassifiable or in attainment for all criteria pollutants.[3]

It is anticipated that the proposed project at the Facility will be considered a major modification under PSD since the proposed project emissions increases for certain criteria pollutants and GHGs are expected to exceed their respective PSD SERs. A preliminary summary of project emissions increases is provided in the following table:

Table 1. Expected Project Emissions Increase[4]

Pollutant	**Project Emissions Increase (tpy)**	**PSD SER Threshold (tpy)**	**PSD Permitting triggered?**
CO	>100	100	Yes
NO_X	>40	40	Yes
PM	>25	25	Yes
PM_{10}	>15	15	Yes
$PM_{2.5}$	>10	10	Yes
SO_2	<40	40	No
VOC	>40	40	Yes
H_2SO_4	<7	7	No
CO_2e	>75,000	75,000	Yes

PSD MODELING ANALYSES

Trinity has prepared this modeling protocol to describe the modeling methodologies and data resources that will be used under the assumption that the proposed project at the Facility will exceed the significant impact levels (SILs). The dispersion modeling analyses will be conducted in consideration of the following guidance documents:

- *Guideline on Air Quality Models* 40 CFR 51, Appendix W (EPA, Revised, January 17, 2017)
- *User's Guide for the AMS/EPA Regulatory Model – AERMOD,* (EPA, April 2018)
- *AERMOD Implementation Guide* (EPA, April 2018)
- *New Source Review Workshop Manual* (EPA, Draft, October, 1990)

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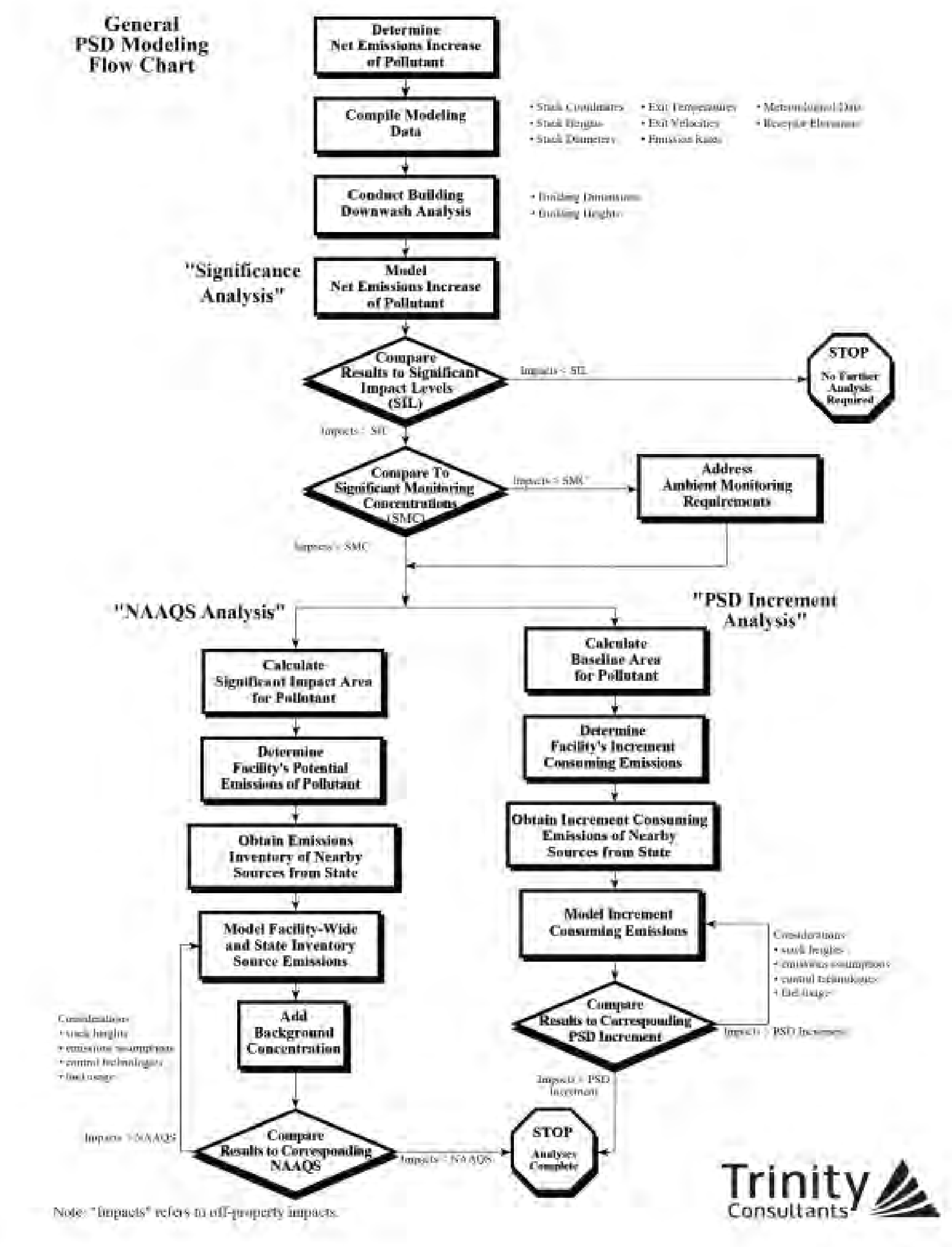
[3] 40 CFR §81.301

[4] The project emissions increase estimates for the proposed project are preliminary and are subject to change.

- *Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS* (EPA, Memorandum from Mr. Stephen Page, March 23, 2010)
- *Draft Guidance for Ozone and Fine Particulate Matter Modeling* (EPA, Memorandum from Mr. Richard A. Wayland, February 10, 2020)
- *Revised Policy on Exclusions from "Ambient Air"* (EPA, Memorandum from Mr. Andrew R. Wheeler, December 2, 2019)
- *GAEPD's PSD Permit Application Guidance Document* (GAEPD, Feb 2017)
- *Guidance for $PM_{2.5}$ Permit Modeling* (EPA, Memorandum from Mr. Stephen Page, May 20, 2014)
- *Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia* (GAEPD, September 19, 2018)
- *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* (EPA, Memorandum from Mr. Richard A Wayland, December 2, 2016) and associated errata document (February 2017)
- *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* (EPA, Memorandum from Mr. Richard A Wayland, April 30, 2019)
- *Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program* (EPA Memorandum from Mr. Peter Tsirigotis, April 17. 2018)
- *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (EPA, Memorandum from Mr. Tyler Fox, March 1, 2011); and
- *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard* (EPA, Memorandum from Mr. R. Chris Owen and Roger Brode, September 30, 2014).

A summary of the tasks that are performed in a standard PSD air quality modeling analysis is presented in the flow chart provided as Figure 3.

Figure 3. PSD Modeling Flow Chart



Significance and NAAQS Analysis

The Significance Analysis is conducted to determine whether the emissions associated with the proposed new construction could cause a significant impact upon the area surrounding the facility. "Significance" is analyzed based on modeling only the new, modified, or associated sources comprising the project; no existing unmodified or unassociated sources are included, neither sources from other regional facilities.

"Significant" impacts are defined by design concentration thresholds commonly referred to as the SIL. WCP will model the project associated sources for significance. For this project, significance modeling will include the facility simple cycle combustion turbines (as modified units) and the natural gas heaters (as associated sources). The emergency fire pump engine and the auxiliary engine will not be modeled as part of the significance analysis.[5] The future potential emissions of each source will be evaluated in the model as a positive emission rate, where past actual emissions (as derived from project baseline data) will be evaluated in the model as a negative emission rate.[6]

Emissions for significance will be evaluated as follows. Evaluations for both use of fuel oil, as well as natural gas, will be evaluated separately and carried through all subsequent analyses (e.g. NAAQS analysis) separately for all short term (non-annual) averaging periods. For the annual averaging period, an annual average emissions rate (based on both use of fuel oil and natural gas) for the facility combustion turbines will be derived and carried through all annual average analyses.

1. Future potential emissions will be based on the maximum capacity of each source following the proposed changes, in conjunction with maximum allowable emission rates, for short term (non-annual) averaging periods. For annual averaging periods for the combustion turbines, emissions will be based on allowable future annual emissions (combined, fuel oil and natural gas usage).
2. Past actual emissions will be derived through;
    i. For NO_2 modeling, CEMS data as recorded by existing facility monitoring equipment, and reported to EPA under the Clean Air Markets Program, in combination with hours of operation to derive hourly emission rates.
    ii. For PM_{10}/$PM_{2.5}$, MMBtu heat input data and hours of operation (along with allowable emission rates in lb/MMBtu) to derive hourly emissions.
    iii. The Facility is considered a baseline source for $PM_{2.5}$ increment, as the facility was an existing permitted and operational facility as of the baseline date (October 2010) for $PM_{2.5}$. Therefore, for $PM_{2.5}$ increment purposes, the project emissions increase for $PM_{2.5}$ increment will consider baseline emissions from the facility for calendar year 2010 as representative of the baseline period for $PM_{2.5}$ increment impacts.
    iv. All non-annual averaging period emission rates, will be based on short term average emissions (e.g. emissions divided by actual hours operated). Annual averaging period emissions will be based on annualized emission rates (emissions divided by 8,760 hours).

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[5] As noted later in this modeling protocol, significance modeling will not consider startup/shutdown (SUSD) as the anticipated startup time, conditions, etc. all occur sub-hourly. The startup time for these units is very short (15 minutes or less). Since the minimum time step of the AERMOD model is 1-hr, no explicit SUSD modeling is proposed to be evaluated as part of this project.

[6] In the case of NO_2 modeling, concerns have been raised regarding use of negative emission rates with Tier 2/Tier 3 modeling options. As Tier 2 modeling methods (e.g. ARM2) are proposed for use with this project, significance modeling will evaluate both the future potential emissions from the project, as well as the past actual (baseline emissions) in the model as part of separate model runs with positive emission rates. Model plot file output data will then be utilized to subtract the past actual model results from the future potential model results, so as no negative emission rates will be utilized in the dispersion model for NO_2 modeling.

Table 2 lists the SIL, NAAQS, and Class II PSD Increments for all relevant NSR regulated pollutants for this project which will be undergoing PSD permitting.[7]

Table 2. Significant Impact Levels, NAAQS, Class II PSD Increments, and Significant Monitoring Concentrations for Relevant NSR Regulated Pollutants

Pollutant	Averaging Period	PSD Class II SIL (µg/m³)	Primary and Secondary NAAQS (µg/m³)	Class II PSD Increment (µg/m³)	Significant Monitoring Concentration (µg/m³)
PM_{10}	24-hour	5	150 (1)	30	10
	Annual	1	--	17	--
$PM_{2.5}$	24-hour	1.2 (2)	35(4)	9 (3)	-- (2)
	Annual	0.2 (2)	12(5)	4 (3)	--
NO_2	1-hour	7.5	188(6)	N/A	--
	Annual	1	100(7)	25	14
CO	1-hr	2,000	40,000	N/A	--
	8-hr	500	10,000	N/A	575

(1) Not to be exceeded more than three times in 3 consecutive years (highest sixth high modeled output).
(2) EPA promulgated $PM_{2.5}$ SILs, Significant Monitoring Concentrations (SMCs), and PSD Increments on October 20, 2010 [75 FR 64864, PSD for Particulate Matter Less Than 2.5 Micrometers Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Final Rule]. The SILs and SMCs became effective on December 20, 2010 (i.e., 60 days after the rule was published in the Federal Register) but the U.S. Court of Appeals decision on January 22, 2013 vacated the SMC and remanded the SIL values back to EPA for reconsideration. EPA has recently provided guidance (August 2016) and a finalized memo (April 2018) which recommended use of a 24-hr $PM_{2.5}$ SIL of 1.2 $\mu g/m^3$, and an annual SIL of 0.2 $\mu g/m^3$. EPA responded to the vacature of the SMCs by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements for $PM_{2.5}$.
(3) The above mentioned court decision did not impact the promulgated increment thresholds for $PM_{2.5}$.
(4) The 3-year average of the 98th percentile 24-hour average concentration (highest eighth high modeled output).
(5) The 3-year average of the annual arithmetic average concentration (highest first high modeled output).
(6) The 3-year average of the 98th percentile of the daily maximum 1-hr average (highest eighth high modeled output).
(7) Annual arithmetic average (highest first high modeled output).

The <u>highest</u> design concentrations out of all given modeling years for each pollutant-averaging time is then compared to the SIL level shown in Table 2 to determine if the ambient air impact is significant. In the case of 24-hour and annual $PM_{2.5}$ evaluations, EPA guidance states that the applicant should determine the maximum concentration at each receptor per year, then average those values on a receptor-specific basis over the 5 years of meteorological data prior to comparing with the appropriate SIL.[8] However, this assessment is only appropriate for the $PM_{2.5}$ NAAQS, as the $PM_{2.5}$ Increment standard is not a statistical standard. Therefore, the year by year results for $PM_{2.5}$ will be compared to the applicable SILs for a determination if a refined analysis for $PM_{2.5}$ increment is required.

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[7] Class I analyses are addressed in a following section.

[8] Please note that WCP will not use averaging for developing the $PM_{2.5}$ SIL results for consideration of the $PM_{2.5}$ Increment. Maximum annual values will be used rather than 5-year average values.

For NO_2 NAAQS modeling, a concatenated meteorological data set to derive the appropriate form of the 1-hr NO_2 NAAQS standard will be utilized. For annual NO_2 NAAQS modeling, each individual year will be processed separately to evaluate maximum annual anticipated impacts.

When modeled design concentrations are less than the applicable SIL, further analyses (NAAQS and PSD Increment) are not required for that pollutant-averaging period, and specific fuel use type.

If modeled impacts are greater than the SIL, a full NAAQS and PSD Increment analysis is required for that pollutant, averaging period, and fuel type to demonstrate that the project neither causes nor contributes to any exceedances.

GAEPD publishes background concentration values on their website and the background monitors as specified by the Georgia EPD for the county of interest will be utilized. [9] The chosen background values are shown in Table 3.

The Sandersville, Georgia $PM_{2.5}$ monitoring location was chosen based on the proximity of this monitoring station to the Facility (~21 km), and its collection of both localized and regional background concentration data specific to Washington County. Meteorological conditions for this monitoring station would also be similar to the project site location, based on their proximity and location within the same geographical region. Also, although the monitoring location is more situated within the Sandersville town area, the area around and surrounding the monitor is decidedly rural, as with the Facility location. Although there are some industrial sources in proximity to the $PM_{2.5}$ monitor, use of background data from this monitor should be sufficiently conservative for this analysis.

The same can be said for the ozone background monitor selection. The Bibb County Macon-Forestry site was chosen as the background ozone monitor for use in the analysis. This monitoring location is approximately 60 km from the Facility, and is located in the same geographical area as the Facility. Therefore, meteorological conditions for both sites should be comparable. Although there are other monitoring sites (e.g. Augusta), within the region, those monitoring sites are in a more urban area (when compared to the Macon-Forestry site) and further away (~100 km) from the facility.

[9] https://epd.georgia.gov/georgia-background-data If more up to date background data is available, that information is requested from the Georgia EPD.

Table 3. Selected Background Concentrations

PSD Pollutant	Averaging Period	Monitor Background Concentration ($\mu g/m^3$)	Metric	Monitor Location
PM_{10}	24-hour	30.0	4^{th} high value over 3-yrs	Statewide Value as Derived by EPD (Fire Station #8)
$PM_{2.5}$	24-hour	18.4	3-yr average of 98^{th} percentile	Sandersville
	Annual	7.9	3-yr arithmetic mean average	
NO_2	1-hour	30.3	3-yr average of 98^{th} percentile	Statewide Value as Derived by EPD (Yorkville)
	Annual	4.5	3-yr arithmetic mean maximum	
CO	1-hour	641	3-yr average of yearly 2^{nd} high	Statewide Value as Derived by EPD (Yorkville)
	8-hour	504		
Ozone	8-hour	0.064 (ppmv)	Annual 4^{th} highest daily maximum 8-hr value, 3-yr average	Macon-Forestry Monitoring Site

Class II Increment Analysis

The PSD regulations were enacted primarily to "prevent significant deterioration" of air quality in areas of the country where the air quality was better than the NAAQS. Therefore, to promote economic growth in areas where attainment of the NAAQS occurs, some deterioration in ambient air concentrations is allowed. To achieve this goal, the U.S. EPA established PSD Increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_2. The PSD Increments are further broken into Class I, II, and III Increments. Since all short-term Class II Increments (Table 4) are not to be exceeded more than once per year, the H2H modeled impacts for 24-hour averaging periods for respective pollutants from among the five modeled meteorological years will be compared against the short-term Increment. The highest annual average concentrations will be compared against the annual Increment.

Table 4. Class II Increments

Pollutant	Averaging Period	Class II Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	9
	Annual	4
PM_{10}	24-hour	30
	Annual	17
NO_2	Annual	25

Ambient Monitoring Requirements

In addition to determining whether the applicant can forego further modeling analyses, the PSD Significance Analysis is also used to determine whether the applicant is exempt from ambient monitoring requirements. To determine whether pre-construction monitoring should be considered, the maximum impacts attributable to the proposed project are assessed against Significant Monitoring Concentrations (SMC). The SMC for the applicable averaging periods for CO, PM_{10}, and NO_2 are provided in 40 CFR §52.21(i)(5)(i) and are listed in Table 2.

A pre-construction air quality analysis using continuous monitoring data may be required for pollutants subject to PSD review per 40 CFR §52.21(m). If either the predicted modeled impact from an emissions increase or the existing ambient concentration is less than the SMC, an applicant may be exempt from pre-construction ambient monitoring. The SMC value for $PM_{2.5}$ was vacated on January 22, 2013, however, EPA responded to the vacature by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements for $PM_{2.5}$. WCP will provide an evaluation of the monitors in place and a justification for why additional site specific monitoring should not be required.

Ozone Ambient Impact Analysis

Elevated ground-level ozone concentrations are the result of photochemical reactions among various chemical species. These reactions are more likely to occur under certain ambient conditions (e.g., high ground-level temperatures, light winds, and sunny conditions). The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). Pursuant to 40 CFR 52.21, ambient ozone monitoring will not be required unless a facility's emissions increase is greater than 100 tpy of VOC or NO_X.

EPA has also recently issued guidance specifying a SIL value for ozone of 1 ppb, and has developed a new potential demonstration (the MERPs guidance) to provide a framework for a Tier 1 demonstration that can illustrate that a project will not cause or contribute to any violation of ambient ozone standards. The February 2019 GAEPD guidance document titled *Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia* will be used to provide a Tier 1 demonstration that ozone impacts from the project will not cause or contribute to ambient air quality levels of ozone. Both VOC and NO_x emissions will be considered. Therefore, an evaluation of the ozone impacts from this project will be conducted through following the EPD February 2019 guidance.

Class I Area Analysis

Class I areas are federally protected areas for which more stringent air quality standards apply to protect unique natural, cultural, recreational, and/or historic values. The Class I area of primary concern for the Facility is the Okefenokee Wilderness, as it is the closest Class I area to the facility at a distance of approximately 233 km. The following Class I areas are located within 300 km of the Facility (with the approximate distance to the Facility listed):[10]

- Okefenokee Wilderness (233 km)
- Cohutta Wilderness (244 km)
- Wolf Island Wilderness (246 km)
- Shining Rock Wilderness (248 km)
- Great Smoky Mountains NP (263 km)
- Joyce Kilmer-Slickrock Wilderness (265km)

All other Class I areas are located at distances greater than 300 km from the Facility.

The Federal Land Managers (FLM) have the authority to protect air quality related values (AQRVs), and to consider in consultation with the permitting authority whether a proposed major emitting facility will have an adverse impact on such values. AQRVs for which PSD modeling is typically conducted include visibility and deposition of sulfur and nitrogen.

The ratio of emissions to Class I distance (e.g., Q/D) for this project for the Class I areas within 300 km will be considered in order to determine if the FLM will require a full AQRV analysis. The FLM's AQRV Work Group (FLAG) 2010 guidance states that a Q/D value of ten or less indicates that AQRV analyses should not be required.[11] A letter will be submitted to the appropriate FLMs (along with the requisite form) for all Class I areas located within 300 km for concurrence with a finding regarding the requirement for AQRV analysis for this project.[12] The Q/D for all Class I areas will be evaluated and demonstrated that impacts will be less than 10.

A significance analysis will be required for the Class I areas referenced above, for potential evaluation of PSD increment impacts upon the Class I area. Details regarding the Class I area significance analysis are as follows.

1. A screening procedure will be utilized evaluating an array of receptors located 50 km from the facility at 1-degree intervals, to compare project emission increase impacts to those receptors at 50 km. [13]

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[10] All distances approximate and based on data obtained from the Class I Area distance tool as published by the FL DEP at https://floridadep.gov/air/air-business-planning/content/class-i-areas-map

[11] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service. 2010. Federal land managers' air quality related values work group (FLAG): phase I report, revised (2010). Natural Resource Report NPS/NRPC/NRR, 2010/232. National Park Service, Denver, Colorado.

[12] EPD will be copied on all correspondence as provided to the appropriate FLMs. If EPD is not copied on any correspondence from the FLM providing concurrence that no AQRV analysis is required, a copy of that correspondence will be provided to GAEPD.

[13] Consistent with EPD guidance, this assumes that the applicable FLMs have determined that no AQRV analyses will be required for the project.

The Class I area Significant Impact Levels (SILs) and PSD Increment thresholds are listed in Table 5. $PM_{2.5}$ Class I SILs are taken from recent EPA guidance (April 2018) regarding appropriate recommended significant impact levels for $PM_{2.5}$.

Table 5. Class I Significant Impact Levels and Increment Thresholds

Pollutant	Averaging Period	Class I SIL (µg/m³)	Class I Increment (µg/m³)
$PM_{2.5}$	24-hour	0.27	2
	Annual	0.05	1
PM_{10}	24-hour	0.3	8
	Annual	0.2	4
NO_2	Annual	0.1	2.5

CLASS II MODELING SETUP

This section of the modeling protocol describes the modeling procedures and data resources utilized in the setup of the Class II Area air quality modeling analyses. The techniques proposed for the air quality analysis are consistent with current EPA guidance.

Modeled Sources

WCP will model the project-associated sources for the significance analysis. This includes the four facility simple cycle combustion turbines, as well as the facility natural gas heaters.

For any off-site impact calculated in the significance modeling analysis that is greater than the SIL for a given pollutant, a NAAQS analysis incorporating nearby sources is required (cumulative impact analysis). For the cumulative impact analysis, all sources at the facility (with the exception of the diesel-fired backup auxiliary generators and diesel-fired emergency fire pump) and the appropriate inventory sources will be included. The diesel-fired backup auxiliary generator and diesel-fired emergency fire pump at the facility are intermittent sources and therefore do no need to be included as an emission source in the modeling analysis.[14]

Model Selection

Dispersion models predict downwind pollutant concentrations by simulating the evolution of the pollutant plume over time and space for specific set of input data. These data inputs include the pollutant's emission rate, source parameters, terrain characteristics, and atmospheric conditions.

According to the 40 CFR 51, Appendix W (the *Guideline)*, the extent to which a specific air quality model is suitable for the evaluation of source impacts depends on (1) the meteorological and topographical

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[14] *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (Memorandum from Mr. Tyler Fox to Regional Air Division Directors, March 1, 2011)

complexities of the area; (2) the level of detail and accuracy needed in the analysis; (3) the technical competence of those undertaking such simulation modeling; (4) the resources available; and (5) the accuracy of the database (i.e., emissions inventory, meteorological, and air quality data).

Taking these factors under consideration, WCP will use the AERMOD modeling system to represent all project emissions sources at the facility. AERMOD is the default model for evaluating impacts attributable to industrial facilities in the near-field (i.e., source receptor distances of less than 50 km), and is the recommended model in the *Guideline*.

AERMOD

The latest version (19191) of the AERMOD modeling system will be used to estimate maximum ground-level concentrations in all Class II Area analyses conducted for this application. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and was promulgated in December 2005 as the preferred model for use by industrial sources in this type of air quality analysis.[15] The AERMOD model has the Plume Rise Modeling Enhancements (PRIME) incorporated in the regulatory version, so the direction-specific building downwash dimensions used as inputs are determined by the Building Profile Input Program, PRIME version (BPIP PRIME), version 04274.[16] BPIP PRIME is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the PRIME enhancements to improve prediction of ambient impacts in building cavities and wake regions.[17]

The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the dispersion and post-processing module.

AERMAP is the terrain pre-processor that is used to import terrain elevations for selected model objects and to generate the receptor hill height scale data that are used by AERMOD to drive advanced terrain processing algorithms. National Elevation Dataset (NED) data available from the United States Geological Survey (USGS) are utilized to interpolate surveyed elevations onto user specified receptor, building, and source locations in the absence of more accurate site-specific (i.e., site surveys, GPS analyses, etc.) elevation data.

AERMET generates a separate surface file and vertical profile file to pass meteorological observations and turbulence parameters to AERMOD. AERMET meteorological data are refined for a particular analysis based on the choice of micrometeorological parameters that are linked to the land use and land cover (LULC) around the meteorological site shown to be representative of the application site.

WCP will use the BREEZE® graphical interface, developed by Trinity Consultants, to assist in developing the model input files for AERMOD. This software program incorporates the most recent versions of AERMOD (dated 19191) and AERMAP (dated 18081) and provides capability for image-generating. Using the

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[15] 40 CFR Part 51, Appendix W, Guideline on Air Quality Models, Appendix A.1 AMS/EPA Regulatory Model (AERMOD).

[16] Earth Tech, Inc., Addendum to the ISC3 User's Guide, The PRIME Plume Rise and Building Downwash Model, Concord, MA.

[17] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised), Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

procedures outlined in the *Guideline* as a reference, the AERMOD dispersion modeling for this project will be performed using only regulatory default options of the model.

Receptor Grid and Coordinate System

Modeled concentrations will be calculated at ground-level receptors placed along the facility fenceline and on a variable Cartesian receptor grid. Fenceline receptors will be spaced no further than 50 meters apart. Beyond the fenceline, receptors will be spaced 100 meters apart on a Cartesian grid extending out to a distance sufficient to resolve the maximum concentration, but at least extending outward to 2 km in all directions. The assessment of the significant impact area (SIA) will utilize a minimum 10 km receptor grid.

In general, the receptors will cover a region extending from all edges of the Facility ambient boundary to the point where impacts from the project are no longer expected to be significant. The boundary will be defined as all areas that are fenced and/or not accessible to the general public as shown in Figure 2.

Please note that per EPA guidance, a reduced receptor grid with only the receptors at which maximum modeled concentrations exceed the SIL is required to be used for NAAQS and Increment modeling. WCP is proposing to use this approach.

Receptor elevations and hill heights required by AERMOD will be determined using the AERMAP terrain preprocessor (version 18081). Terrain elevations from the USGS 1-arc second NED will be used for AERMAP processing.

In all modeling analysis data files, the location of emission sources, structures, and receptors will be represented in the UTM coordinate system, zone 17, NAD-83.

Urban versus Rural Dispersion Options

This section describes the performance of Land-use analysis for the purpose of determining the type of dispersion coefficients most appropriate for the application. The two sets of dispersion coefficients available in AERMOD are urban and rural. The goal of this land-use analysis is to estimate the percentage of urban and rural types of land cover within the study area. The study area is defined as a region centered on the site and having a radius of 3-km. The land-use types corresponding to urban areas are the "Commercial/Industrial/ Transportation" and "High density residential" types, where all other land cover types are associated with a rural setting.

As specified in Section 7.2.1.1.b.i of the *Guideline*, a 3 km radius centered at the Facility was considered for the land-use analysis. A visual evaluation of aerial imagery clearly defines this area as rural, as shown in the following Figure 4.

Figure 4. Site Aerial Image

Therefore, AERMOD will be evaluated considering rural dispersion coefficients.

Meteorological Data

The Facility is located in Washington County, GA. EPD has provided the most recent five years of meteorological data on their website.[18] Assignment of station pairings to each county was based on distance to the centroid of the county, climatological zone, data collection period, and data completeness criteria. For Washington County, GAEAPD provides surface data from the Middle Georgia Regional Airport, and upper air data from Peachtree City/Falcon Field. The Middle Georgia Regional Airport meteorological station is located at 32.688 degrees (latitude) and -83.654 degrees (longitude) and is approximately 77 km Southwest of the Facility.

Meteorological data sets provided by GAEPD covered the time period from 2015 to 2019, and include meteorological data processed both with and without the ADJ_U* option of AERMET. The 2015 to 2019 meteorological data set with the ADJ_U* option, will be utilized for this modeling analysis. A representativeness evaluation comparing the surface characteristics around the facility's location, and the project site, will be included within the application submittal for this project.

[18] https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling/georgia-aermet-meteorological-data EPD provides prescribed recommended meteorological data on a county by county basis.

Building Downwash Analysis

AERMOD incorporates the Plume Rise Model Enhancements (PRIME) downwash algorithms. Direction specific building parameters required by AERMOD are calculated using the BPIP-PRIME preprocessor (version 04274). Facility structures will be built into the model and downwash influences will be evaluated appropriately.

Source Types and Parameters

The AERMOD dispersion model allows for emission units to be represented as point, area, or volume sources. Point sources with unobstructed vertical releases will be modeled with their actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity). All Facility sources to be evaluated in this modeling assessment will have vertical unobstructed releases, and will therefore be evaluated at their actual release velocity conditions.

GEP Stack Height Analysis

EPA has promulgated stack height regulations that restrict the use of stack heights in excess of "Good Engineering Practice" (GEP) in air dispersion modeling analyses. Under these regulations, that portion of a stack in excess of the GEP height is generally not creditable when modeling to determine source impacts. This essentially prevents the use of excessively tall stacks to reduce ground-level pollutant concentrations.

This equation is limited to stacks located within 5L of a structure. Stacks located at a distance greater than 5L are not subject to the wake effects of the structure. The wind direction-specific downwash dimensions and the dominant downwash structures used in this analysis are determined using BPIP. In general, the lowest GEP stack height for any source is 65 meters by default.[19] A preliminary evaluation has indicated that none of the Facility emission unit stacks will exceed GEP height.

Regional Source Inventory (Class II Modeling)

For any off-site impact calculated in the Significance Analysis that is greater than the SIL for a given pollutant, a NAAQS analysis incorporating nearby sources is required. The initial off-site inventory radius will be the radius of the pollutant-specific largest SIA (except for 1-hour NO_2) to a maximum distance of 50 km. WCP will use EPD's "PSD Modeling Tool" to obtain the off-site inventory sources necessary for the analysis.[20] WCP will only consider Synthetic Minor or minor sources within 5 km of the Facility for any required refined modeling analysis, unless that source is within a cluster of other industrial sources.

WCP will then apply the "20D" rule to eliminate sources based on their distance from the site in kilometers and quantity of emissions in tons per year. Emissions from all stacks within a single facility and other facilities that are located near one another (within 2 km) will be totaled. For long-term models (annual), if the total emissions for the group of sources calculated are less than twenty times the distance from the source to the SIA distance, the source will eliminated from the modeling analysis. For short-term models (24-hour or shorter), if the total emissions for the group of sources are less than twenty times the distance

[19] 40 CFR §51.100(ii)

[20] https://psd.georgiaair.org/inventory

from the source to the site, the source will be eliminated from the modeling. This approach is consistent with GAEPD's February 2017 document titled *PSD Permit Application Guidance Document*.

Further refinements may be conducted in consultation with the GAEPD, especially for evaluation of 1-hour NO_2. Alternative methods may be used in accordance with *Guideline* which states that "*The number of nearby sources to be explicitly modeled in the air quality analysis is expected to be few except in unusual situations. In most cases, the few nearby sources will be located within the first 10 to 20 km from the source(s) under consideration. Owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources, no attempt is made here to comprehensively define a "significant concentration gradient." Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority…"*.[21] Therefore, for this project, if the SIL for 1-hr NO_2 is exceeded, it is proposed that regional inventory sources no more than 20 km from the facility be included in the refined modeling analysis.[22]

NO_2 Modeling Approach

The revised *Guideline* now indicates Ambient Ratio Method 2 (ARM2) has replaced ARM as the regulatory default Tier 2 NO_2 modeling method. WCP proposes to utilize ARM2 for modeling NO_2 for the 1-hour and annual SIL and NAAQs modeling assessments, and for the annual PSD increment modeling assessment. Should further refinement be needed with Tier 3 modeling methods, such as the Ozone Limiting Method (OLM) or Plume Volume Molar Ratio Method (PVMRM), WCP will contact the GAEPD. As discussed in an earlier section of this modeling protocol, significance modeling utilizing ARM2 will model both future potential emissions, and past actual emissions, as positive emission rates in separate modeling files, and subtract the results at each receptor manually using plot file output information.

Startup/Shutdown Modeling and Variable Load Modeling

As discussed in an earlier section of this modeling protocol, Startup/Shutdown modeling will not be conducted for project significance modeling, as startup/shutdown activities are all sub-hourly events (15 minutes or less) for these types of combustion turbines. Only normal source operating conditions will be evaluated as part of the proposed facility changes.

From a load basis, the project emissions source parameters for 50% load, 75% load and 100% load will be developed, and evaluated to determine the worst case modeled impacts for each applicable pollutant. That load basis (on a pollutant by pollutant basis) will be carried through as the normal operating condition in all modeling assessments for the project.

Particulate Matter Precursor Emissions Modeling

The September 2018 GAEPD guidance document titled *Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia* has established a state-specific Tier 1 procedure for a

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[21] Appendix W, Section 8.3.3.b.iii

[22] This assumes the significant impact area distance for the project for 1-hr NO_2 will be less than 20 km. If greater than 20 km, the maximum inventory source distance utilized in the refined modeling analysis will be set to the significant impact area distance. At such a distance, it is highly unlikely that there would be temporal or spatial pairing of real world facility emission plumes between Facility sources and regional modeled sources.

demonstration that a project will not cause or contribute to ambient air quality impacts of $PM_{2.5}$ associated with secondary $PM_{2.5}$ emissions. The modeling report to be provided with the permit application for this project will include a Tier 1 assessment for secondary $PM_{2.5}$ in accordance with GAEPD's MERPs guidance. Precursor based emission impacts on all $PM_{2.5}$ modeling for this project will be considered.

ADDITIONAL IMPACTS MODELING METHODOLOGY

The required additional impacts evaluations for this project will include a growth analysis and a soil and vegetation analysis. It is anticipated that no Class II visibility areas (e.g. state parks) will be within the significant impact areas derived for the project, and therefore no Class II visibility assessment will be evaluated for this project.

TOXIC AIR POLLUTANT MODELING

EPD regulates the emissions of toxic air pollutants through a program approved under the provisions of GRAQC Rule 391-3-1-.02(2)(a)3(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the EPD's review of toxic air pollutant emissions as part of air permit reviews are contained in EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (the *Toxics Guideline*).[23]

The *Toxics Guideline* has established the Allowable Ambient Concentration (AAC) and Minimum Emission Rate (MER) for each TAP, which are included in Appendix A of the *Toxics Guideline*. The MERs were established by EPD by using worst-case dispersion scenarios and using the SCREEN3 computer air dispersion model. The MERs were stablished considering both short-term and long-term exposures, where the lowest MER calculated for each substance was selected as the MER for that substance. Thus, the facility-wide emission rates in lb/yr for each TAP will be used to compare to the MERs. If a pollutant's facility-wide emission rate is below the MER, no further analysis will be required for that pollutant. For any pollutant whose emission rate is above its respective MER, WCP will provide a demonstration that facility-wide emissions for that pollutant will not result in an ambient impact above its respective AAC.

AERMOD will be used for the air toxics analysis, and all applicable elements of the modeling methodology outlined for the PSD air dispersion modeling analysis will be utilized as developed for that analysis, including the effects of building downwash.

SUMMARY AND APPROVAL OF MODELING PROTOCOL

WCP is supplying this written preliminary protocol so that the EPD can formally comment on, and approve the methodologies to be used for this analysis, and request any additional information. WCP requests a written response to this protocol as soon as possible. All modeling files and reports will be provided electronically, as part of the permit application.

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[23] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May 2017.

If you have any questions about the material presented in this letter, require additional information, or would like to talk about any of the proposed methods, please do not hesitate to call me at 678-441-9977 Ext. 228.

Sincerely,

TRINITY CONSULTANTS

Justin Fickas
Managing Consultant

cc: Mr. James Eason (EPD)
Mr. Eric Cornwell (EPD)

GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Richard E. Dunn, Director

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November 25, 2020
Mr. Justin Fickas
Trinity Consultants
Tel: 678-441-9977 ext. 228
jfickas@trinityconsultants.com

Subject: **Review of PSD Air Dispersion Modeling Protocol**
Washington County Power, LLC, Sandersville, Washington County, GA

Dear Mr. Fickas:

We have reviewed the air quality dispersion modeling protocol received on October 29, 2020 from the Washington County Power LLC (hereinafter "WCP") located in Sandersville, GA (Washington County). WCP proposes a major modification project at the WCP site allowing the four existing simple cycle turbines to burn either natural gas up to 3,000 hour/year or fuel oil up to 500 hour/year per turbine. We find that the submitted protocol generally conforms to the procedures and guidelines we use to assess Prevention of Significant Deterioration (PSD) and air toxic impact modeling projects. However, we do have the following comments:

1. General Modeling Considerations: WCP should use the latest version of AERMOD (version 19191) following the Georgia EPD Draft PSD Permit Application Guidance Document[1] (hereinafter "GA PSD Guidance Document") and the 2017 revisions to EPA's Guideline on Air Quality Models (hereinafter "Appendix W") for the air impact modeling of all criteria pollutants. As provided in the AERMOD User's Guide, any DEFAULT option may be employed in the modeling. Use of Non-Default options is subject to case-by-case approval by the EPA Region 4 office. Please use BPIP PRIME (version 04274) to assess building downwash dimensions and GEP stack heights. Stacks of heights equal to or in excess of the GEP height should be modeled using the GEP height. Please use AERMAP (version 18081) to assess all model receptor elevations above sea level with the USGS NED database. Model receptors should be spaced along the ambient air boundary and should extend outward from the facility to ensure that the maximum impact location and the significant impact distance are located with an area of 100-m meter spacing. Model receptors at 100-m spacing should extend outward from the facility at least 2 km in all directions but may need to extend even further. Larger grid spacing may be used if the ultimate design value is determined by re-modeling with a 100-m or finer grid around a more coarsely resolved design concentration. All design concentrations equal to or greater than 90% of the design concentrations should be resolved at the 100-m or finer grid resolution. All model coordinates, including building corners, should be referenced using the NAD83 datum. Please assess source base elevations using AERMAP, if appropriate, otherwise, use plant grade elevations. GA EPD requests that WCP submit a facility plot showing the facility fence-line in the permit application. Any areas outside the facility fence-line will be considered ambient air. WCP

[1] https://epd.georgia.gov/document/document/georgia-epd-psd-permit-application-guidance-document-posted-february-3-2017/download

also needs to substantiate the selection of urban vs rural dispersion option following Section 7.2.1.1 "Dispersion Coefficients" in Appendix W as part of the PSD modeling application. Please refer to ATTACHMENT 1 of this letter for generally applicable modeling references.

AERMOD meteorological data set for the period 2015-2019 can be obtained at the GA EPD website[2]. WCP should provide the meteorological data representative analysis by comparing the seasonal surface characteristics such as albedo, Bowen ratio, and surface roughness for each season and sector using AERSURFACE (version 20060). ATTACHMENT 2 is an example for developing your own justification.

In general, all emission calculations used to determine modeled emission rates must include detailed documentation to allow GA EPD Stationary Source Permitting Program (SSPP) to review and approve the emissions. Thus, WCP must provide a justification for all modeled emission rates including past actuals and future potential emissions. In the justification, WCP should provide step-by-step procedures on calculations of past actual emissions including unit conversions. According to Table 8.2 of Appendix W, the emissions modeled in the significant impact analysis should reflect the post-project potential emission rates for all new, modified, or associated units. SSPP will confirm correctness of unit types, i.e. new, modified, or associated. Please note that total $PM_{2.5}$ emissions should include all filterable and condensable (e.g., sulfuric acid mist) $PM_{2.5}$ emissions. Please carefully distinguish between NO_X and NO_2 and provide your definition of NO_2 in the air quality modeling report. Please refer to ATTACHMENT 3 for more information.

As required by Appendix W, the applicant should evaluate the impact of the secondary formation of $PM_{2.5}$ from its precursors (NO_X and SO_2) and ozone from its precursors (NO_X and VOCs) following the EPA's "*Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier l Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*" (April 30, 2019) and GA EPD's "*Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and $PM_{2.5}$ in Georgia*" (February 25, 2019) for both Class I and Class II impact analyses if applicable.

2. Class I Increment Analysis: EPA/EPD retain purview over Class I increment consumption, so both agencies should get a copy of any project correspondence you may have with any Federal Land Manager (FLM). If the project is not required to assess Air Quality Related Values (AQRVs) at any Class I area, you may perform Class I area increment screening modeling with AERMOD (version 19191). The receptors should be placed approximately 1-km evenly spaced on a 50-km arc from WCP towards the Class I areas being evaluated. If the initial screening modeling indicates the project will exceed applicable significance levels at any Class I area, the applicant may use CALPUFF or other Lagrangian models to calculate the air quality impact at the Class I area as the second level screening modeling. If the impact modeled during the second level screening exceeds the applicable significance levels at any Class I area, a refined analysis including the offsite inventory is needed. The increment screening modeling should not employ building downwash, nor should it include the assessment of fugitive emissions.

3. Class II Area Analysis: In addition to those discussed in "General Modeling Considerations", a tiered approach is recommended for determining the air quality impact of NO_2 emission from point sources. GA EPD concurs with the applicant's proposal to utilize the default AERMOD ARM2 option for all short and long-term analysis of NO_2 emissions. The default setting for the NO_2/NO_X ratio is a minimum value of 0.5 at the highest NO_X levels and a maximum value of 0.9 at the lowest NO_X levels.

[2] https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling/georgia-aermet-meteorological-data

The applicant should consult with GA EPD and EPA Region 4 if a Tier 3 approach such as the Ozone Limited Method or Plume Volume Molar Ratio Method is used. GA EPD concurs with the applicant's proposal to evaluate the impact from the post-project potential emission and past actual emission (also baseline) separately.

4. Off-site Inventory: If the project is significant for any averaging period of any criteria pollutants, a cumulative air quality analysis (both NAAQS and PSD increment if applicable) will be required. If a full PSD increment analysis is required for $PM_{2.5}$, the analysis should include secondary $PM_{2.5}$ impacts from NO_X emissions associated with the project as well as NO_X emissions from existing $PM_{2.5}$ increment consumers in the inventory of nearby sources.

   Please follow the off-site emission inventory development guidance in GA PSD Guidance Document and Section 8.3.3 of Appendix W. The minor source baseline date[3] (MSBD) for the annual NO_2 is May 5, 1988 (statewide) and for $PM_{2.5}$ is October 20, 2011 (statewide). The PM_{10} MSBD for Washington County is June 6, 1978.

   The GA EPD SSPP will review and approve your on-site emission inventory including the stack parameters and emission rates. For off-site emission inventories, GA EPD has made available a PSD inventory tool[4]. Please use this tool to develop an initial off-site emissions inventory within a sum of the radius of the pollutant-specific largest significant impact area (SIA) and 50 km of the WCP facility except for 1-hour NO_2 and 1-hour SO_2. This inventory can be supplemented and corrected as necessary with approval from GA EPD. If any missing inventory information is identified, the applicant should consult GA EPD SSPP regarding your specific missing data handling technique.

   Off-site sources can be screened out from the cumulative analysis using a "20D" approach, provided they are not located within the SIA. WCP must provide clear substantiation as to the determination of SIA for each pollutant that exceeds its SIL. Please note that the largest SIA determined for any averaging period should be used for all averaging periods if there is a need to do cumulative modeling for each pollutant, with the exception of the 1-hour NO_2 NAAQS. For 1-hour NO_2 NAAQS modeling, WCP indicates that the maximum inventory source distance may be set to the SIA distance if the SIA distance is greater than 20 km. We recommend that professional judgement be exercised for inclusion in the modeling inventory any major NO_X sources just beyond the SIA distance.

   The emissions of the sources within 2 km should be grouped together for the "20D" evaluation. Details can be found at Section 5.3 of GA EPD PSD Guidance Document. Any sources including synthetic minor or minor sources within the significant impact distance should be considered in the cumulative modeling. The applicant should also follow Section 8.3.3 and Table 8-2 of Appendix W to identify the nearby sources. The applicant may propose to use emissions that are different from that in the Georgia PSD inventory tool (e.g., typical actual emissions). These requests will be evaluated by GA EPD on a case-by-case basis. Please be sure to submit written substantiation of the "20D" screening calculations as part of WCP's modeling application.

5. Ambient Concentrations: The ambient concentrations for year 2017-2019 period can be found at GA EPD website[5]. Table 3 of protocol appears to conform to the most recent Division approved values.

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[3] https://epd.georgia.gov/document/document/list-minor-source-baseline-dates-updated-april-2017/download
[4] https://psd.gaepd.org/inventory/
[5] https://epd.georgia.gov/document/document/georgia-background-data/download

6. Preconstruction Monitoring Evaluation: The applicant should submit the Monitoring *De Minimis* concentration comparison and Ozone Impact Analysis to determine whether the proposed application is required to conduct preconstruction monitoring for the applicable criteria pollutants and/or ozone. Please check GA PSD Guidance Document for details.

7. Additional Impacts: All additional impacts studies will be limited to no more than the largest significant impact distance from the project site. Additional impacts studies do not include National Monuments, unless specifically requested by a Federal Land Manager. Please check GA PSD Guidance Document for details.

   WCP indicates that no Class II visibility assessment will be evaluated for this project because no Class II visibility areas (e.g. state parks) are expected to be within the significant impact areas derived for the project. However, if any Class II visibility areas happen to be within the significant impact areas, WCP should seek for GA EPD's approval on the methodology for additional impacts analyses and submit the analysis results as part of the application.

8. Startup/shutdown Modeling and Variable Load Modeling: WCP indicates that no startup/shutdown (SUSD) modeling will be conducted as the anticipated startup time, conditions, etc. all occur sub-hourly. However, WCP has not demonstrated that such a conclusion complies with Section 8.2.2.(d) of Appendix W. WCP should provide information about startup/shutdown modeling and variable load modeling. See ATTACHMENT 4 of this letter for additional details.

9. Modeled Sources: WCP indicates that the diesel-fired backup auxiliary generators and diesel-fired emergency fire pump at the facility are intermittent sources and therefore do not need to be included in the modeling. Additional justification for exclusion of these sources should be provided including:
   - Quantification of emissions from these sources.
   - Frequency of testing and typical hours of testing per year.
   - Whether the sources are tested on a routine or non-routine basis.
   - Whether the sources are routinely tested simultaneously.
   - Permit conditions related to the operation of these sources.

10. Air Toxics: Air toxics modeling should be conducted in accordance with the GA EPD Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, 2017. The GA EPD SSPP will determine which TAPs need to be assessed. Please review the AAC values[6] at the applicable averaging periods and ensure the use of the most recently updated values. Please document the basis for any updated values as part of the modeling portion of the application.

    AERMOD (version 19191) is recommended for the air toxics modeling. Air toxics model receptors should extend to at least 2 km outward from the project site, and there must be sufficient receptors to resolve the Maximum Ground-Level Concentration (MGLC). If any receptors are located at terrain elevations in excess of the lowest stack height in the model, AERMOD must be used to assess impacts at those receptors. The air toxics modeling must be conducted with all on-site sources of the same pollutant.

Please refer to GA PSD Guidance Document Appendices A and B for completeness of your application. If EPA issues any guidance, or models which you believe may affect the modeling of this project subsequent to this protocol approval letter, please contact GA EPD to verify the ability to incorporate such

[6] https://epd.georgia.gov/document/document/appendix-list-tap-aac-and-mer-updated-oct-2018/download

guidance or models in the assessments of this application. If you have specific questions on issues that develop after you receive this protocol approval letter, please contact EPD too. This protocol approval is valid for six (6) months from today, unless otherwise stipulated. If you have any question, please contact Byeong-Uk Kim at Byeong.Kim@dnr.ga.gov or 404-362-4851.

Sincerely,

Byeong-Uk Kim, Ph.D.
Manager, Data & Modeling Unit
Georgia Department of Natural Resources
Environmental Protection Division - Air Protection Branch

Attachments
Attachment 1: Generally Applicable Modeling References
Attachment 2: Example Comparisons of surface characteristics at Airport and Facility
Attachment 3: Modeled Emission Rates
Attachment 4: Startup/Shutdown Modeling and Variable Load Modeling

Attachment 1: Generally Applicable Modeling References

Generally Applicable Modeling References

1990, Draft New Source Review Workshop Manual.

1993, Automatic or Blanket Exemptions for Excess Emissions During Startup and Shutdown Under PSD, Memorandum from John B. Rasnic to Linda M. Murphy.

1995, User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, Volume I - User Instructions, Volume II - Description of Model Algorithms, EPA-454/B-95-003a & b.

1999, State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown, Memorandum from Steven A. Herman and Robert Perciasepe to Regional Administrators.

2002, User Instructions for the Revised ISCST3 Model (version 02035).

2004, User's Guide to the Building Profile Input Program (BPIP), Revised with the PRIME algorithm (BPIPPRM, version 04274), EPA-454/R-93-038.

2007, Interpretation of "Ambient Air" In Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD), https://www.epa.gov/sites/production/files/2015-07/documents/leaseair.pdf

2010, Federal Land Managers' (FLMs) Air Quality Related Values Work Group (FLAG) Phase I Report - Revised, https://irma.nps.gov/DataStore/Reference/Profile/2125044

2011, Additional Clarification Regarding Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS. March 1, 2011. https://www3.epa.gov/ttn/scram/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

2014, Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard. September 30, 2014. https://www3.epa.gov/ttn/scram/guidance/clarification/NO2_Clarification_Memo-20140930.pdf

2014, US EPA Guidance for $PM_{2.5}$ Permit Modeling, https://www3.epa.gov/scram001/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

2016, Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program. https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf

2017, GA EPD Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling

2017, Georgia EPD PSD Permit Application Guidance Document, https://epd.georgia.gov/air-protection-branch-technical-guidance-0/air-quality-modeling

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2018, User's Guide for the AERMOD Terrain Preprocessor (AERMAP, version18081), EPA-454/B-18-004, https://www3.epa.gov/ttn/scram/models/aermod/aermap/aermap_userguide_v18081.pdf

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ATTACHMENT 2: Example Comparisons of surface characteristics at Airport and Facility

		Airport			Facility		
Season	Wind Sector	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness
Winter	1 of 12	0.15	0.80	0.26	0.16	0.86	0.15
Winter	2 of 12	0.15	0.80	0.41	0.16	0.86	0.19
Winter	3 of 12	0.15	0.80	0.40	0.16	0.86	0.18
Winter	4 of 12	0.15	0.80	0.31	0.16	0.86	0.12
Winter	5 of 12	0.15	0.80	0.31	0.16	0.86	0.15
Winter	6 of 12	0.15	0.80	0.11	0.16	0.86	0.09
Winter	7 of 12	0.15	0.80	0.16	0.16	0.86	0.09
Winter	8 of 12	0.15	0.80	0.15	0.16	0.86	0.09
Winter	9 of 12	0.15	0.80	0.23	0.16	0.86	0.10
Winter	10 of 12	0.15	0.80	0.34	0.16	0.86	0.25
Winter	11 of 12	0.15	0.80	0.47	0.16	0.86	0.31
Winter	12 of 12	0.15	0.80	0.49	0.16	0.86	0.33
Winter	**Average**	**0.15**	**0.80**	**0.30**	**0.16**	**0.86**	**0.17**
Spring	1 of 12	0.14	0.57	0.29	0.15	0.59	0.20
Spring	2 of 12	0.14	0.57	0.46	0.15	0.59	0.25
Spring	3 of 12	0.14	0.57	0.46	0.15	0.59	0.26
Spring	4 of 12	0.14	0.57	0.37	0.15	0.59	0.19
Spring	5 of 12	0.14	0.57	0.33	0.15	0.59	0.22
Spring	6 of 12	0.14	0.57	0.12	0.15	0.59	0.12
Spring	7 of 12	0.14	0.57	0.17	0.15	0.59	0.11
Spring	8 of 12	0.14	0.57	0.17	0.15	0.59	0.11
Spring	9 of 12	0.14	0.57	0.24	0.15	0.59	0.12
Spring	10 of 12	0.14	0.57	0.37	0.15	0.59	0.29
Spring	11 of 12	0.14	0.57	0.51	0.15	0.59	0.38
Spring	12 of 12	0.14	0.57	0.50	0.15	0.59	0.43
Spring	**Average**	**0.14**	**0.57**	**0.33**	**0.15**	**0.59**	**0.22**
Summer	1 of 12	0.15	0.34	0.37	0.16	0.39	0.30
Summer	2 of 12	0.15	0.34	0.53	0.16	0.39	0.43
Summer	3 of 12	0.15	0.34	0.54	0.16	0.39	0.56
Summer	4 of 12	0.15	0.34	0.54	0.16	0.39	0.49
Summer	5 of 12	0.15	0.34	0.35	0.16	0.39	0.43
Summer	6 of 12	0.15	0.34	0.14	0.16	0.39	0.24
Summer	7 of 12	0.15	0.34	0.19	0.16	0.39	0.18
Summer	8 of 12	0.15	0.34	0.23	0.16	0.39	0.26
Summer	9 of 12	0.15	0.34	0.26	0.16	0.39	0.17
Summer	10 of 12	0.15	0.34	0.39	0.16	0.39	0.32
Summer	11 of 12	0.15	0.34	0.53	0.16	0.39	0.48
Summer	12 of 12	0.15	0.34	0.53	0.16	0.39	0.67
Summer	**Average**	**0.15**	**0.34**	**0.38**	**0.16**	**0.39**	**0.38**
Fall	1 of 12	0.15	0.80	0.37	0.16	0.86	0.30
Fall	2 of 12	0.15	0.80	0.53	0.16	0.86	0.42
Fall	3 of 12	0.15	0.80	0.54	0.16	0.86	0.56
Fall	4 of 12	0.15	0.80	0.54	0.16	0.86	0.49
Fall	5 of 12	0.15	0.80	0.35	0.16	0.86	0.43
Fall	6 of 12	0.15	0.80	0.14	0.16	0.86	0.24
Fall	7 of 12	0.15	0.80	0.19	0.16	0.86	0.17
Fall	8 of 12	0.15	0.80	0.23	0.16	0.86	0.26
Fall	9 of 12	0.15	0.80	0.26	0.16	0.86	0.16
Fall	10 of 12	0.15	0.80	0.39	0.16	0.86	0.30
Fall	11 of 12	0.15	0.80	0.53	0.16	0.86	0.46
Fall	12 of 12	0.15	0.80	0.53	0.16	0.86	0.66
Fall	**Average**	**0.15**	**0.80**	**0.38**	**0.16**	**0.86**	**0.37**

		Airport – Facility			(Airport – Facility)/Airport		
Season	**Wind Sector**	**Δ (Albedo)**	**Δ (Bowen Ratio)**	**Δ (Surface Roughness)**	**% (Albedo)**	**% (Bowen Ratio)**	**% (Surface Roughness)**
Winter	1 of 12	-0.01	-0.06	0.11	-6.7%	-7.5%	41.6%
Winter	2 of 12	-0.01	-0.06	0.23	-6.7%	-7.5%	54.7%
Winter	3 of 12	-0.01	-0.06	0.22	-6.7%	-7.5%	54.8%
Winter	4 of 12	-0.01	-0.06	0.19	-6.7%	-7.5%	60.7%
Winter	5 of 12	-0.01	-0.06	0.17	-6.7%	-7.5%	52.5%
Winter	6 of 12	-0.01	-0.06	0.02	-6.7%	-7.5%	17.0%
Winter	7 of 12	-0.01	-0.06	0.07	-6.7%	-7.5%	44.6%
Winter	8 of 12	-0.01	-0.06	0.06	-6.7%	-7.5%	42.0%
Winter	9 of 12	-0.01	-0.06	0.13	-6.7%	-7.5%	56.9%
Winter	10 of 12	-0.01	-0.06	0.09	-6.7%	-7.5%	25.6%
Winter	11 of 12	-0.01	-0.06	0.16	-6.7%	-7.5%	34.7%
Winter	12 of 12	-0.01	-0.06	0.16	-6.7%	-7.5%	32.4%
Winter	**Average**	**-0.01**	**-0.06**	**0.13**	**-6.7%**	**-7.5%**	**43.9%**
Spring	1 of 12	-0.01	-0.02	0.09	-7.1%	-3.5%	32.2%
Spring	2 of 12	-0.01	-0.02	0.21	-7.1%	-3.5%	45.1%
Spring	3 of 12	-0.01	-0.02	0.20	-7.1%	-3.5%	42.9%
Spring	4 of 12	-0.01	-0.02	0.19	-7.1%	-3.5%	50.0%
Spring	5 of 12	-0.01	-0.02	0.12	-7.1%	-3.5%	35.4%
Spring	6 of 12	-0.01	-0.02	0.00	-7.1%	-3.5%	0.0%
Spring	7 of 12	-0.01	-0.02	0.06	-7.1%	-3.5%	37.2%
Spring	8 of 12	-0.01	-0.02	0.06	-7.1%	-3.5%	33.7%
Spring	9 of 12	-0.01	-0.02	0.12	-7.1%	-3.5%	48.8%
Spring	10 of 12	-0.01	-0.02	0.07	-7.1%	-3.5%	20.3%
Spring	11 of 12	-0.01	-0.02	0.13	-7.1%	-3.5%	25.1%
Spring	12 of 12	-0.01	-0.02	0.07	-7.1%	-3.5%	14.1%
Spring	**Average**	**-0.01**	**-0.02**	**0.11**	**-7.1%**	**-3.5%**	**32.9%**
Summer	1 of 12	-0.01	-0.05	0.06	-6.7%	-14.7%	17.2%
Summer	2 of 12	-0.01	-0.05	0.10	-6.7%	-14.7%	19.7%
Summer	3 of 12	-0.01	-0.05	-0.02	-6.7%	-14.7%	-4.1%
Summer	4 of 12	-0.01	-0.05	0.05	-6.7%	-14.7%	9.5%
Summer	5 of 12	-0.01	-0.05	-0.08	-6.7%	-14.7%	-21.5%
Summer	6 of 12	-0.01	-0.05	-0.10	-6.7%	-14.7%	-74.5%
Summer	7 of 12	-0.01	-0.05	0.01	-6.7%	-14.7%	5.8%
Summer	8 of 12	-0.01	-0.05	-0.03	-6.7%	-14.7%	-13.3%
Summer	9 of 12	-0.01	-0.05	0.09	-6.7%	-14.7%	34.5%
Summer	10 of 12	-0.01	-0.05	0.07	-6.7%	-14.7%	18.8%
Summer	11 of 12	-0.01	-0.05	0.06	-6.7%	-14.7%	10.5%
Summer	12 of 12	-0.01	-0.05	-0.14	-6.7%	-14.7%	-26.8%
Summer	**Average**	**-0.01**	**-0.05**	**0.01**	**-6.7%**	**-14.7%**	**1.7%**
Fall	1 of 12	-0.01	-0.06	0.06	-6.7%	-7.5%	17.3%
Fall	2 of 12	-0.01	-0.06	0.11	-6.7%	-7.5%	21.0%
Fall	3 of 12	-0.01	-0.06	-0.02	-6.7%	-7.5%	-3.7%
Fall	4 of 12	-0.01	-0.06	0.05	-6.7%	-7.5%	9.5%
Fall	5 of 12	-0.01	-0.06	-0.08	-6.7%	-7.5%	-21.5%
Fall	6 of 12	-0.01	-0.06	-0.10	-6.7%	-7.5%	-74.5%
Fall	7 of 12	-0.01	-0.06	0.02	-6.7%	-7.5%	9.6%
Fall	8 of 12	-0.01	-0.06	-0.03	-6.7%	-7.5%	-12.1%
Fall	9 of 12	-0.01	-0.06	0.11	-6.7%	-7.5%	40.4%
Fall	10 of 12	-0.01	-0.06	0.09	-6.7%	-7.5%	24.0%
Fall	11 of 12	-0.01	-0.06	0.08	-6.7%	-7.5%	14.1%
Fall	12 of 12	-0.01	-0.06	-0.13	-6.7%	-7.5%	-24.8%
Fall	**Average**	**-0.01**	**-0.06**	**0.01**	**-6.7%**	**-7.5%**	**3.5%**

ATTACHMENT 3: Modeled Emission Rates

The applicant is reminded of the need to provide clear written substantiation of each modeled emission rate. The written substantiation should include the assumptions used in the calculations along with the emission factor and activity factor if emissions are products of emission factor times activity factor.

GA EPD will be looking for the following information as part of its PSD modeling application review:

Table 1. Modeled past actual emissions per emission unit. Please supply the supporting calculations including all assumptions.

Pollutant	**Averaging Period**	**Modeled Past Actual Emissions[7] (lb/hr)**
NO_2	1-hour	
NO_2	Annual	
CO	1-hour	
CO	8-hour	
PM_{10}	24-hour	
PM_{10}	Annual	
$PM_{2.5}$	24-hour	
$PM_{2.5}$	Annual	

Table 2. Modeled future potential emissions per emission unit. Please supply the supporting calculations including assumptions.

Pollutant	**Averaging Period**	**Future Potential Emissions Used in PSD Applicability (tpy)**	**Modeled Future Potential Emissions (lb/hr)**
NO_2	1-hour		
NO_2	Annual		
CO	1-hour		
CO	8-hour		
PM_{10}	24-hour		
PM_{10}	Annual		
$PM_{2.5}$	24-hour		
$PM_{2.5}$	Annual		

If the applicant uses different emission rates for Class I analyses and Class II analyses, the applicant should provide Tables B1 and B2 for each Class I and Class II analysis, separately.

[7] Past actual emissions are based on normal operations over the previous two years.

ATTACHMENT 4. Startup/Shutdown Modeling and Variable Load Modeling

GA EPD wants to remind WCP that there is no blanket exemption for emissions occurring during startup/shutdown (SUSD) periods of operations at the facility from the BACT requirements or for the PSD air quality analyses. The emissions occurring during SUSD periods of operation contribute to the hourly emissions for the hour of operation that includes SUSD. SUSD is one of the "operating conditions" that should be evaluated pursuant to Section 8.2.2.(d) of Appendix W.

WCP must provide clear and credible substantiation for exclusion of SUSD periods of operation from the PSD modeling exercise. GA EPD reserves the right to require the inclusion of SUSD operations in the air quality modeling analysis based on its review of WCP's written substantiation.

WCP's written substantiation in support of (or in support against) inclusion of SUSD periods of operation in the air quality modeling should include (but not limited to) the following information:

- A comparison of emissions and stack parameters expected during SUSD conditions to emissions and stack parameters during permitted allowable (routine) conditions for each turbine for each fuel type
- The duration (minutes, hours, days) and frequency of occurrence of SUSD events (# per day, # per year) for each turbine for each fuel type.
- Total number of anticipated startup events per calendar year, on a per turbine basis. Each event hour in duration.
- Total number of anticipated shutdown events per calendar year, on a per turbine basis. Each event hour in duration.

This could include consideration of any permit provisions that may limit the frequency, duration, or the times of day when SUSD conditions can occur. An example table is provided as follows:

	Duration of SUSD Events (Hours)	**Emissions per Pollutant (lb/hr)**	**Stack Exit Velocity (ft/sec)**	**Stack Exit Temp (F)**
Routine Operation				
Startup				
Shutdown				

APPENDIX D. EMISSIONS INFORMATION FOR MODELING

Table D-1. Modeling Parameters of Project Emission Sources

Model ID	Source Description	Stack Height (ft)	Exit Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)	Normal Operation Heat Input Natural Gas (MMBtu/hr)	Normal Operation Heat Input Fuel Oil (MMBtu/hr)	SUSD Heat Input Natural Gas (MMBtu/hr)	SUSD Heat Input Fuel Oil (MMBtu/hr)	Other Pollutants Gas Only Operation (hrs/yr)	Other Pollutants Oil Only Operation (hrs/yr)	NO_x and CO - Normal Op Gas Only Operation (hrs/yr)	NO_x and CO - Normal Op Oil Only Operation (hrs/yr)	NO_x and CO - SUSD Gas Only Operation (hrs/yr)	NO_x and CO - SUSD Oil Only Operation (hrs/yr)
T1	Turbine No. 1	90.00	1,113	160.00	18.50	1,766	1,890	1,478	1,582	3,000	500	2,700	450	300	50
T2	Turbine No. 2	90.00	1,113	160.00	18.50	1,766	1,890	1,478	1,582	3,000	500	2,700	450	300	50
T3	Turbine No. 3	90.00	1,113	160.00	18.50	1,766	1,890	1,478	1,582	3,000	500	2,700	450	300	50
T4	Turbine No. 4	90.00	1,113	160.00	18.50	1,766	1,890	1,478	1,582	3,000	500	2,700	450	300	50
H1	Fuel Heater No. 1	15.00	780	16.00	1.30	10.10	--	--	--	8,760	--	--	--	--	--
H2	Fuel Heater No. 2	15.00	780	16.00	1.30	10.10	--	--	--	8,760	--	--	--	--	--
TANK	Fuel Oil Tank	48.00	Ambient	--	--	--	--	--	--	8,760	--	--	--	--	--

Table D-2. Modeling Parameters of Project Emission Sources - Turbines at 100% Load

Model ID	Source Description	UTM17 East (m)	UTM17 North (m)	Stack Height (m)	Base Elevation (m)	Exit Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
T1	Turbine No. 1	315241.6	3663195.3	27.43	98.49	873.71	48.77	5.64
T2	Turbine No. 2	315203.1	3663213.8	27.43	98.91	873.71	48.77	5.64
T3	Turbine No. 3	315151.0	3663238.0	27.43	99.32	873.71	48.77	5.64
T4	Turbine No. 4	315114.0	3663256.0	27.43	99.48	873.71	48.77	5.64
H1	Fuel Heater No. 1	315172.0	3663166.0	4.57	98.19	688.71	4.88	0.396
H2	Fuel Heater No. 2	315174.0	3663170.0	4.57	98.25	688.71	4.88	0.396
TANK	Fuel Oil Tank	315,006.36	3,663,382.82	14.63	103.24	0.00	0.001	1.000

Table D-3. Modeling Parameters of Project Emission Sources - Turbines at 75% Load

Model ID	Source Description	UTM17 East (m)	UTM17 North (m)	Stack Height (m)	Base Elevation (m)	Exit Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
T1	Turbine No. 1	315241.6	3663195.3	27.43	98.49	873.71	39.01	5.64
T2	Turbine No. 2	315203.1	3663213.8	27.43	98.91	873.71	39.01	5.64
T3	Turbine No. 3	315151.0	3663238.0	27.43	99.32	873.71	39.01	5.64
T4	Turbine No. 4	315114.0	3663256.0	27.43	99.48	873.71	39.01	5.64

Table D-4. Modeling Parameters of Project Emission Sources - Turbines at 50% Load

Model ID	Source Description	UTM16 East (m)	UTM16 North (m)	Stack Height (m)	Base Elevation (m)	Exit Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
T1	Turbine No. 1	315241.6	3663195.3	27.43	98.49	708.49	36.41	5.64
T2	Turbine No. 2	315203.1	3663213.8	27.43	98.91	708.49	36.41	5.64
T3	Turbine No. 3	315151.0	3663238.0	27.43	99.32	708.49	36.41	5.64
T4	Turbine No. 4	315114.0	3663256.0	27.43	99.48	708.49	36.41	5.64

Table D-5. Modeling Parameters of Turbines - SUSD

Model ID	Source Description	UTM17 East (m)	UTM17 North (m)	Stack Height (m)	Base Elevation (m)	Exit Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)
T1A	Turbine No. 1 SUSD	315241.6	3663195.3	27.43	98.49	733.91	40.97	5.64
T2A	Turbine No. 1 SUSD	315203.1	3663213.8	27.43	98.91	733.91	40.97	5.64
T3A	Turbine No. 1 SUSD	315151.0	3663238.0	27.43	99.32	733.91	40.97	5.64
T4A	Turbine No. 1 SUSD	315114.0	3663256.0	27.43	99.48	733.91	40.97	5.64

Table D-6. Emission Factors for Project Emission Sources

Emission Unit	Fuel Type	Emission Factor (lb/MMBtu)[1,2]			
		CO	NO_X	PM_{10}	$PM_{2.5}$
Turbines	Fuel Oil	4.05E-02	0.14	1.42E-02	1.42E-02
Turbines	Natural Gas	1.82E-02	3.00E-02	1.37E-02	1.37E-02
Turbines	Fuel Oil - SUSD	7.29E-02	0.25	--	--
Turbines	Natural Gas - SUSD	3.28E-02	5.39E-02	--	--
Heaters	Natural Gas	8.24E-02	9.80E-02	7.45E-03	7.45E-03

1. Emission factors are detailed in PSD emission calc.
2. Emission factors for the heaters are taken from AP-42 Section 1.4, *Natural Gas Combustion*, Table 1.4-1 and 1.4-2 (07/98).

Table D-7. Modeled Emission Rates for Project Emission Sources -Turbines at 100% Load

Model ID	Source Description	Short-Term Emissions - Turbines Natural Gas Operating Scenario (lb/hr)				Short-Term Emissions - Turbines Fuel Oil Operating Scenario (lb/hr)				Annual (tpy)
		CO	NO_X	PM_{10}	$PM_{2.5}$	CO	NO_X	PM_{10}	$PM_{2.5}$	NO_X
T1	Turbine No. 1	32.20	52.89	24.19	24.19	76.6	264.1	26.84	26.84	152.73
T2	Turbine No. 2	32.20	52.89	24.19	24.19	76.6	264.1	26.84	26.84	152.73
T3	Turbine No. 3	32.20	52.89	24.19	24.19	76.6	264.1	26.84	26.84	152.73
T4	Turbine No. 4	32.20	52.89	24.19	24.19	76.6	264.1	26.84	26.84	152.73
H1	Fuel Heater No. 1	0.83	0.99	7.53E-02	7.53E-02	0.83	0.99	7.53E-02	7.53E-02	4.34
H2	Fuel Heater No. 2	0.83	0.99	7.53E-02	7.53E-02	0.83	0.99	7.53E-02	7.53E-02	4.34

Table D-8. Modeled Emission Rates for Turbines - SUSD

Model ID	Source Description	Short-Term Emissions - Natural Gas (lb/hr)		Short-Term Emissions -Fuel Oil (lb/hr)	
		CO	NO_X	CO	NO_X
T1A	Turbine No. 1 SUSD	48.51	79.68	115.4	397.9
T2A	Turbine No. 2 SUSD	48.51	79.68	115.4	397.9
T3A	Turbine No. 3 SUSD	48.51	79.68	115.4	397.9
T4A	Turbine No. 4 SUSD	48.51	79.68	115.4	397.9

Table D-9. Modeled Emission Rates for Project Emission Sources - Turbines at 100% Load

Model ID	Source Description	Short-Term Emissions - Turbines Natural Gas Operating Scenario (g/s)				Short-Term Emissions - Turbines Fuel Oil Operating Scenario (g/s)				Annualized Emissions (g/s)
		CO	NO_X	PM_{10}	$PM_{2.5}$	CO	NO_X	PM_{10}	$PM_{2.5}$	NO_X
T1	Turbine No. 1	4.06	6.66	3.05	3.05	9.65	33.28	3.38	3.38	4.39
T2	Turbine No. 2	4.06	6.66	3.05	3.05	9.65	33.28	3.38	3.38	4.39
T3	Turbine No. 3	4.06	6.66	3.05	3.05	9.65	33.28	3.38	3.38	4.39
T4	Turbine No. 4	4.06	6.66	3.05	3.05	9.65	33.28	3.38	3.38	4.39
T1A	Turbine No. 1 SUSD	6.11	10.04	--	--	14.54	50.14	--	--	--
T2A	Turbine No. 2 SUSD	6.11	10.04	--	--	14.54	50.14	--	--	--
T3A	Turbine No. 3 SUSD	6.11	10.04	--	--	14.54	50.14	--	--	--
T4A	Turbine No. 4 SUSD	6.11	10.04	--	--	14.54	50.14	--	--	--
H1	Fuel Heater No. 1	0.10	0.12	9.48E-03	9.48E-03	0.10	0.12	9.48E-03	9.48E-03	--
H2	Fuel Heater No. 2	0.10	0.12	9.48E-03	9.48E-03	0.10	0.12	9.48E-03	9.48E-03	--

Table D-10. Modeled Emission Rates for Project Emission Sources - Turbines at 75% Load

Model ID	Source Description	Short-Term Emissions - Natural Gas (g/s)				Short-Term Emissions - Fuel Oil (g/s)				Annualized Emissions (g/s)
		CO	NO_X	PM_{10}	$PM_{2.5}$	CO	NO_X	PM_{10}	$PM_{2.5}$	NO_X
T1	Turbine No. 1	3.04	5.00	2.29	2.29	7.24	24.96	2.54	2.54	3.30
T2	Turbine No. 2	3.04	5.00	2.29	2.29	7.24	24.96	2.54	2.54	3.30
T3	Turbine No. 3	3.04	5.00	2.29	2.29	7.24	24.96	2.54	2.54	3.30
T4	Turbine No. 4	3.04	5.00	2.29	2.29	7.24	24.96	2.54	2.54	3.30

Table D-11. Modeled Emission Rates for Project Emission Sources - Turbines at 50% Load

Model ID	Source Description	Short-Term Emissions - Natural Gas (g/s)				Short-Term Emissions - Fuel Oil (g/s)				Annualized Emissions (g/s)
		CO	NO_X	PM_{10}	$PM_{2.5}$	CO	NO_X	PM_{10}	$PM_{2.5}$	NO_X
T1	Turbine No. 1	2.03	3.33	1.52	1.52	4.82	16.64	1.69	1.69	2.20
T2	Turbine No. 2	2.03	3.33	1.52	1.52	4.82	16.64	1.69	1.69	2.20
T3	Turbine No. 3	2.03	3.33	1.52	1.52	4.82	16.64	1.69	1.69	2.20
T4	Turbine No. 4	2.03	3.33	1.52	1.52	4.82	16.64	1.69	1.69	2.20

Table D-12. Production Data for Past Actual Emissions for Significance Modeling

		T1			T2			T3			T4		
Month	Year	Operating Time	NOx (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	Heat Input (MMBtu)
10	2018	17.45	0.464	27,214.06	47.98	1.791	79,106.20	67.13	2.532	108,820.80	35.02	0.742	53,585.63
11	2018	--	--	--	--	--	--	--	--	--	--	--	--
12	2018	--	--	--	6.1	0.275	10,789.79	6.35	0.282	11,059.72	--	--	--
1	2019	--	--	--	--	--	--	--	--	--	--	--	--
2	2019	--	--	--	--	--	--	--	--	--	--	--	--
3	2019	0.92	0.038	979.28	1.1	0.061	1,391.95	0.83	0.045	1,034.94	0.9	0.05	1,072.88
4	2019	--	--	--	4.13	0.175	7,073.43	4.03	0.178	6,855.40	--	--	--
5	2019	22.07	0.564	34,615.28	13.98	0.543	22,819.73	7.51	0.27	12,309.19	--	--	--
6	2019	49.39	1.249	77,554.05	22.04	0.814	35,422.77	22.01	0.733	35,234.59	32.8	0.649	51,823.00
7	2019	23.61	0.639	37,239.39	87.62	3.046	141,423.16	86.39	2.826	138,330.22	121.66	2.451	191,934.98
8	2019	65.87	1.615	104,085.51	73	2.466	118,577.29	72.54	2.323	116,818.15	--	--	--
9	2019	138.03	3.822	217,892.17	108.66	3.926	174,598.70	108.01	3.697	172,043.86	157.52	3.257	249,492.17
10	2019	54.44	1.503	85,572.71	58.19	2.139	95,216.97	57.38	1.962	92,952.13	66.34	1.487	104,699.00
11	2019	--	--	--	11.93	0.576	21,958.07	5.33	0.254	9,387.78	--	--	--
12	2019	0.89	0.064	954.24	0.95	0.064	1,087.22	0.85	0.058	1,029.85	0.87	0.061	1,055.29
1	2020	--	--	--	--	--	--	--	--	--	--	--	--
2	2020	--	--	--	--	--	--	--	--	--	--	--	--
3	2020	28.16	0.845	41,651.87	0.9	0.052	1,087.49	0.85	0.044	1,072.80	0.8	0.057	977.31
4	2020	--	--	--	--	--	--	--	--	--	--	--	--
5	2020	--	--	--	--	--	--	--	--	--	--	--	--
6	2020	15.55	0.436	24,612.98	49.72	1.862	80,186.20	38.03	1.268	60,452.45	8.25	0.168	13,174.45
7	2020	131.57	3.651	209,170.94	81.51	2.992	132,923.49	72.37	2.494	117,412.87	32.76	1.968	51,748.69
8	2020	--	--	--	40.62	1.503	66,181.31	40.41	1.446	65,572.56	--	--	--
9	2020	16.45	0.451	26,234.97	54.62	1.975	89,267.82	52.94	1.88	86,273.76	--	--	--
	Sum	**564.4**	**15.341**	**887,777.45**	**663.05**	**24.26**	**1,079,111.57**	**642.96**	**22.292**	**1,036,661.07**	**456.92**	**10.89**	**719,563.39**

Table D-13. Past Actual Emissions for Significance Modeling

EU	1-hr Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/hr)	1-hr or 8-hr CO[3] (lb/hr)	1-hr NOx[1] (lb/hr)	Annual NOx[2] (lb/hr)	24-hr PM_{10}[3] (lb/hr)	Annual PM_{10}[3] (lb/hr)	24-hr $PM_{2.5}$[3] (lb/hr)	Annual $PM_{2.5}$[3] (lb/hr)
T1	1,572.96	50.67	28.68	54.36	1.75	21.55	0.69	21.55	0.69
T2	1,627.50	61.59	29.68	73.18	2.77	22.30	0.84	22.30	0.84
T3	1,612.33	59.17	29.40	69.34	2.54	22.09	0.81	22.09	0.81
T4	1,574.81	41.07	28.71	47.67	1.24	21.57	0.56	21.57	0.56

1. Based on actual heat input or NO_X emissions from October 2018 - September 2020 and acutual hours of operation.
2. Based on actual heat input or NO_X emissions from October 2018 - September 2020 and potention hours during the period (i.e. 8,760 hrs x 2)
3. Short-term emission based on 1-hr Heat Input. Annual emission based on Annual Heat Input. Emissions factors are detailed below for natural gas combustion.

Total PM_{10}	1.37E-02	lb/MMBtu
Total $PM_{2.5}$	1.37E-02	lb/MMBtu
CO	1.82E-02	lb/MMBtu

Table D-14. Past Actual Emissions for Significance Modeling

EU	1-hr or 8-hr CO (g/s)	1-hr NOx (g/s)	Annual NOx (g/s)	24-hr PM_{10} (g/s)	Annual PM_{10} (g/s)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)
T1	3.61	6.85	0.22	2.72	8.75E-02	2.72	8.75E-02
T2	3.74	9.22	0.35	2.81	0.11	2.81	0.11
T3	3.70	8.74	0.32	2.78	0.10	2.78	0.10
T4	3.62	6.01	0.16	2.72	7.09E-02	2.72	7.09E-02

Table D-15 Production Data for Baseline Emissions for Increment Modeling

	T1		T2		T3		T4	
Year	Operating Time	Heat Input (MMBtu)	Operating Time	Heat Input (MMBtu)	Operating Time	Heat Input (MMBtu)	Operating Time	Heat Input (MMBtu)
2009	46.59	69,580	120.51	193,617	120.26	190,970	27.53	41,644
2010	310.77	488,920	519.57	844,354	541.08	876,852	301.89	474,373
Sum	**357.36**	**558,501**	**640.08**	**1,037,971**	**661.34**	**1,067,822**	**329.42**	**516,017**

Table D-16. Baseline Emissions for Increment Modeling

EU	1-hr Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/hr)	24-hr $PM_{2.5}$[3] (lb/hr)	Annual $PM_{2.5}$[3] (lb/hr)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)
T1	1,562.85	31.88	21.41	0.44	2.70	5.50E-02
T2	1,621.63	59.24	22.22	0.81	2.80	0.10
T3	1,614.63	60.95	22.12	0.83	2.79	0.11
T4	1,566.44	29.45	21.46	0.40	2.70	5.08E-02

1. Based on actual heat input in 2009 and 2010 and acutual hours of operation.
2. Based on actual heat input in 2009 and 2010 and potention hours during the period (i.e. 8,760 hrs x 2)
3. Short-term emission based on 1-hr Heat Input. Annual emission based on Annual Heat Input. Emissions factors are detailed below for natural gas combustion.

Total $PM_{2.5}$	1.37E-02	lb/MMBtu

Table D-17. Emission Increase for Significance Modeling

	Natural Gas							
	NAAQS	NAAQS	NAAQS/Increment		NAAQS		Increment	
EU	1-hr or 8-hr CO (g/s)	1-hr NO_x (g/s)	24-hr PM_{10} (g/s)	Annual PM_{10} (g/s)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)
PTE[1]								
T1	4.06	6.66	3.05	3.05	3.05	3.05	3.05	3.05
T2	4.06	6.66	3.05	3.05	3.05	3.05	3.05	3.05
T3	4.06	6.66	3.05	3.05	3.05	3.05	3.05	3.05
T4	4.06	6.66	3.05	3.05	3.05	3.05	3.05	3.05
Past Actual[2]								
T1	3.61	6.85	2.72	8.75E-02	2.72	8.75E-02	2.70	5.50E-02
T2	3.74	9.22	2.81	0.11	2.81	0.11	2.80	0.10
T3	3.70	8.74	2.78	0.10	2.78	0.10	2.79	0.11
T4	3.62	6.01	2.72	7.09E-02	2.72	7.09E-02	2.70	5.08E-02
Emission Increase[3]								
T1	0.44	--	0.33	2.96	0.33	2.96	0.35	2.99
T2	0.32	--	0.24	2.94	0.24	2.94	0.25	2.95
T3	0.35	--	0.27	2.95	0.27	2.95	0.26	2.94
T4	0.44	--	0.33	2.98	0.33	2.98	0.34	3.00

	Fuel Oil								NAAQS/Increment
	NAAQS	NAAQS	NAAQS/Increment		NAAQS		Increment		
EU	1-hr or 8-hr CO (g/s)	1-hr NO_x	24-hr PM_{10} (g/s)	Annual PM_{10} (g/s)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)	24-hr $PM_{2.5}$ (g/s)	Annual $PM_{2.5}$ (g/s)	Annual NO_x (g/s)
PTE[1]									
T1	9.65	33.28	3.38	3.38	3.38	3.38	3.38	3.38	4.39
T2	9.65	33.28	3.38	3.38	3.38	3.38	3.38	3.38	4.39
T3	9.65	33.28	3.38	3.38	3.38	3.38	3.38	3.38	4.39
T4	9.65	33.28	3.38	3.38	3.38	3.38	3.38	3.38	4.39
Past Actual[2]									
T1	3.61	6.85	2.72	8.75E-02	2.72	8.75E-02	2.70	5.50E-02	0.22
T2	3.74	9.22	2.81	0.11	2.81	0.11	2.80	0.10	0.35
T3	3.70	8.74	2.78	0.10	2.78	0.10	2.79	0.11	0.32
T4	3.62	6.01	2.72	7.09E-02	2.72	7.09E-02	2.70	5.08E-02	0.16
Emission Increase[3]									
T1	6.03	--	0.67	3.29	0.67	3.29	0.68	3.33	--
T2	5.91	--	0.57	3.28	0.57	3.28	0.58	3.28	--
T3	5.94	--	0.60	3.28	0.60	3.28	0.59	3.28	--
T4	6.03	--	0.66	3.31	0.66	3.31	0.68	3.33	--

1. Based on Table D-9.
2. Based on actual emissions for the past 24-months as detailed in Table D except for PM2.5 increment run which is based on 2009 and 2010 actual emissions as detailed in Table D-16.
3. Emission Increase = PTE - Past Actual

Table D-18. Modeled Emission Rates for Precursors (MERPs) Analysis - Class II SIL

Pollutant	Project Emission Increase (tpy)	Default MERP Values[1] 8-hr Ozone (tpy)	Daily $PM_{2.5}$ (tpy)	Annual $PM_{2.5}$ (tpy)
NO_X	565.97	156	4,014	7,427
SO_2	N/A	--	667	6,004
VOC	95.21	3,980	--	--
MERP (%)[3]		365%	14.10%	7.62%
SIL (µg/m³)		1.00 ppb	1.20	0.20
MERP (µg/m³)			0.17	1.52E-02
Background Ozone (ppb)		64		
Ozone Cumulative Analysis[4]		67.65		
NAAQS Ozone (ppb)		70		

1. Per guidance from GA EPD, the EPD MERPs guidance value was relied for Class II MERPs, as that value is more conservative than the information present in the most recent EPA MERPs guidance. Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and PM2.5 in Georgia Guidance, dated February 25, 2019 - https://epd.georgia.gov/document/document/georgia-merps-guidance-updated-february-25-2019/download
2. Per EPA guidance and confirmation from EPD (Email from Mr. Byeong Kim dated April 9, 2021), only pollutants that trigger PSD should be included in Tier I MERPs evaluation. SO2 emissions are below the SER for this propsoed project and therefore are not included in MERPs evaluation.
3. Ozone MERP (%) = (NO_X project emissions increase / NO_X 8-hr O_3 MERP) + (VOC project emissions increase /
$PM_{2.5}$ MERP (%) = (NO_X project emissions increase / NO_X MERP) + (SO_2 project emissions increase / SO_2 MERP)
4. Ozone Cumulative Analysis = $Background\_Ozone$ + Ozone MERP% $* SIL\_Ozone$

Table D-19. Modeled Emission Rates for Precursors (MERPs) Analysis - $PM_{2.5}$ Class II

Program	Emissions	NO_X[1] (tpy)	Default MERP Daily $PM_{2.5}$ (tpy)	Default MERP Annual $PM_{2.5}$ (tpy)	MERP Daily $PM_{2.5}$ (µg/m³)	MERP Annual $PM_{2.5}$ (µg/m³)
NAAQS	Facility-Wide PTE	624.48			0.19	1.68E-02
Increment (Emissions Increase Since October 20, 2010)	1. Project Emission Increase[4] 2. Site Emission Increase[4]	624.48	4,014	7,427	0.69	6.26E-02
	3. Off-Site Source Project Emission Increase[5] 4. Emissions from Permitted Sources Not Yet Fully Operative[5]	1,699				
	Total[6]	2,323				

1. Per EPA guidance and confirmation from EPD (Email from Mr. Byeong Kim dated April 9, 2021), only pollutants that trigger PSD should be included in Tier I MERPs evaluation. SO_2 emissions are below the SER for this proposed project and therefore are not included in MERPs evaluation.
2. Per guidance from GA EPD, the EPD MERPs guidance value was relied for Class II MERPs, as that value is more conservative than the information present in the most recent EPA MERPs guidance. Guidance on the Use of EPA's MERPs to Account for Secondary Formation of Ozone and PM2.5 in Georgia Guidance, dated February 25, 2019 - https://epd.georgia.gov/document/document/georgia-merps-guidance-updated-february-25-2019/download
3. $PM_{2.5}$ MERP = (NO_X Emissions / NO_X MERP) x SIL (µg/m³), where SILs are

Daily $PM_{2.5}$	1.20	µg/m³
Annual $PM_{2.5}$	0.20	µg/m³

4. The faciltiy does not have projects since October 20, 2010 that could impact NOx emissions. However, site wide PTE was used here for the facility as a conservative estimate of increases since the baseline period.

5. Based on project emissions increase or potential emissions from NOx inventory sources within 50 km of the site. Assumed that any facility which has not had a project for new or modified equipment since the 2010 baseline/trigger date for $PM_{2.5,}$ no substantial actual increment consumption has occured from those sources.
Details are summarized in Table D-21.
6. Sum of emissions increase from components 1 - 4.

Table D-20. Modeled Emission Rates for Precursors (MERPs) Analysis - Class I SIL

Parameters	Project Emission Increase (tpy)	Default MERP Values[1] Daily $PM_{2.5}$ (tpy)	Annual $PM_{2.5}$ (tpy)	Units
NO_X Emissions	565.97	1,000		(tpy)
Concentration		1.77E-02	4.88E-04	(µg/m³)
MERP (µg/m³)		9.99E-03	2.76E-04	(µg/m³)

1. Data from Qlik (https://www.epa.gov/scram/merps-view-qlik) for Allendale, SC at 220 km distance (closest Class I area 230 ish km) 90 ft tall stack, and 1000 tpy. Scaled concentration value based on project emissions increase for NOx.

Table D-21. MERP Inventory Sources

AIRS #	Facility Name	City	County	Classification	UTM Zone	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_x Estimated Emissions (tpy)	List of Permit or Permit Amendment After October 2010	Date of Permit or Permit Amendment Issued	Description of Project	Impact on NOx Emissions? (tpy)
900019	Central State Hospital	Milledgeville	Baldwin	A	17	319873	3684827	22.07	64.39	Conservativly assumed as precursor consumers			64.39
900,035.00	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	Milledgeville	Baldwin	A	17	308,127.00	3,660,004.00	7.77	410.06	V-03-0	6/22/2011	Title V Renewal	No
										V-03-1	9/7/2012	This Amendment changes the facility name from Southern Natural Gas Company to Southern Natural Gas Company, L.L.C.	No
										V-04-0	4/26/2017	Title V Renewal	No
30300004	IMERYS Sandersville Calcine Plant	Sandersville	Washington	A	17	329651	3648799	20.46	114.45	Conservativly assumed as precursor consumers			114.45
30300006	Thiele Kaolin Company - Sandersville Plant	Sandersville	Washington	A	17	330,074.01	3,649,291.54	20.43	203.23	V-02-1	2/15/2011	Add LPG (propane) as a permitted fuel for Spray Dryers 1-5 (SD01-SD05)	39.21
										V-02-2	3/28/2012	The increased permitted operating hours of two diesel-fired generators (SG01 and SG02) from 200 hrs/yr to 1000 hrs/yr for each.	34.00
										V-03-0	8/15/2012	Title V Renewal	No
										V-04-0	4/30/2018	Title V Renewal	No
30300008	IMERYS Deepstep Road Plant	Sandersville	Washington	A	17	324,420.32	3,655,596.44	12.01	173.93	V-03-0	5/30/2013	Title V Renewal	No
										V-04-0	10/17/2018	Title V Renewal	No
30300009	Burgess Pigment Company	Sandersville	Washington	A	17	329532	3650049	19.51	76.34	Conservativly assumed as precursor consumers			76.34
30300035	KaMin - Sandersville	Sandersville	Washington	A	17.00	329,959.00	3,649,142.00	20.45	125.01	V-02-2	1/19/2012	Plant applied for permission to manufacture treated clay products using additives (in either liquid or powder form) in the kaolin manufacturing process.	3.13
										V-03-0	8/11/2014	Title V Renewal	No
										V-04-0	2/11/2020	Title V Renewal	No
30300040	AL Sandersville	Warthen	Washington	A	17.00	326,387.00	3,666,032.00	11.55	725.33	V-06-0	10/7/2014	Title V Renewal	No
										V-06-1	4/30/2018	Permit Condition 6.2.1 to read "The Permittee shall monitor the sulfur content of the natural gas burned in combustion turbines T1, T2, T3, T4, T5, T6, T7, and T8 by the submittal of a semiannual analysis of the gas by the supplier or a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less".	No
										V-07-0	7/13/3030	Title V Renewal	No
30300005	Kent-Tenn Clay (Plts 51 & 52)	Sandersville	Washington	SM	17	329507	3648668	20.46	11.30	Conservativly assumed as precursor consumers			11.30
30300021	Kent-Tenn Clay (Plt 53)	Sandersville	Washington	SM	17	325077	3654428	13.27	25.60	Conservativly assumed as precursor consumers			25.60
30300047	Trojan Battery Company, LLC	Sandersville	Washington	SM	17	328356	3653199	16.58	6.02	Conservativly assumed as precursor consumers			6.02
14100009	Pittman Construction Company	Sparta	Hancock	SM	17	322527	3681162	19.35	16.50	Conservativly assumed as precursor consumers			16.50
30300057	ARI Railcar Services, LLC	Tennille	Washington	SM	17	329809	3644912	23.47	8.60	Conservativly assumed as precursor consumers			8.60
900044	Rath Refractories	Milledgeville	Baldwin	SM	17	286291	3663587	28.89	99.00	Conservativly assumed as precursor consumers			99.00
30100010	Jebco, Inc.	Warrenton	Warren	SM	17	343863	3697257	44.48	100.00	Conservativly assumed as precursor consumers			100.00
31900009	BASF Corporation, Edgar Plant	Mcintyre	Wilkinson	A	17.00	292,936.00	3,636,304.00	34.95	336.00	V-03-0	2/12/2015	Title V Renewal	No
										V-03-1	11/8/2019	This minor modification without construction updates the reporting frequency in Condition 6.1.4 from the quarterly to semiannual	No
										V-04-0	2/3/2021	Title V Renewal	No
31900013	BASF Corporation, Toddville Plant	Mcintyre	Wilkinson	A	17	291108	3637205	35.47	173.00	V-03-0	4/9/2014	Title V Renewal	No
										V-04-0	9/20/2019	Title V Renewal	No
31900004	BASF Corporation, Gordon Plant	Gordon	Wilkinson	A	17	281193	3640502	40.90	184.00	V-03-0	10/7/2014	Title V Renewal	No
										V-04-0	1/15/2020	Title V Renewal	No
900031	Triumph Aerostructures, LLC - Vought Aircraft Division	Milledgeville	Baldwin	A	17	286579	3663070	28.60	30.48	Conservativly assumed as precursor consumers			

Table D-21. MERP Inventory Sources

AIRS #	Facility Name	City	County	Classification	UTM Zone	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_X Estimated Emissions (tpy)	List of Permit or Permit Amendment After October 2010	Date of Permit or Permit Amendment Issued	Description of Project	Impact on NOx Emissions? (tpy)
31900029	Carbo Ceramics, Inc. - Toomsboro Plant	Toomsboro	Wilkinson	A	17	300929	3636634	30.20	2,425.43	V-02-2	3/24/2011	Revisions to Monitoring and record keeping of NOx emissions	No
										V-02-3	4/5/2012	Allow up to 60 days to submit period reports	No
										V-03-0	5/30/2014	Title V Renewal	No
										V-03-1	11/17/2014	A dry sorbent injection (DSI) system will be added to each of the four (4) existing kilns to reduce the combined sulfuric acid (H2SO4) emissions from the kilns to less than 7 tons per year	No
										V-03-2	2/4/2015	install a grit dryer and screen/classifier for Lines 1-4 and baghouses to control particulate matter emissions	7.73
										V-03-3	2/4/2016	Install a pilot plant that includes a small 0.75 MMBTU/hr. natural gas fired burner, a mixing/fluidized bed chamber, and small baghouse.	0.23
										V-03-4	2/18/2016	A small fluidized bed dryer with a heat input of 2 MMBTU/hr. to be installed for drying coated finished product after it has been run through a weak metallic solution and rinsed in water.	0.77
										V-03-5	9/15/2016	Installation and operation of baghouse COATBH01.	No
										V-03-6	4/19/2018	Addition of a 5 MMBtu/hr Pellet Coater/Dryer (PCD2) to Line 2 pelletizing and handling equipment.	3.50
										V-04-0	2/12/2020	Title V Renewal	No
31900027	Carbo Ceramics, Inc. - McIntyre Plant	Mcintyre	Wilkinson	A	17	297617	3636464	32.04	1,102.18	V-03-3	12/21/2010	A new wet scrubber (SC01) to control PM and SO_2 emissions from the New Raw Material Calciner No. 2 (CLN2). The new scrubber SC01 will replace the existing Baghouses BH44 and BH45.	No
										V-03-4	4/5/2012	Template Conditions 6.1.3, 6.1.4 and 8.14.1 were updated in September 2011 to allow up to 60 days to submit periodic reports. Alternative reporting deadlines are allowed per 40 CFR 70.6, 40 CFR 60.19(f) and 40 CFR 63.10(a).	No
										V-03-5	5/14/2013	Replace the existing product cooler and baghouse with a new vibrating cooler (VC) and baghouse (BH46) to control emissions from the vibratory cooler.	No
										V-04-0	8/20/2013	Title V Renewal	No
										V-05-0	5/6/2021	Title V Renewal	No
23700010	Interfor U.S. Inc. - Eatonton Sawmill	Eatonton	Putnam	A	17	280106	3680554	39.10	88.65	Conservativly assumed as precursor consumers			88.65
30100003	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	Warrenton	Warren	A	17	346925	3697998	47.06	41.43	Conservativly assumed as precursor consumers			41.43
30300046	Georgia Industrial Minerals, Inc.	Sandersville	Washington	B	17	317008	3656707	6.81	100.00	Conservativly assumed as precursor consumers			100.00
14100002	Corridor Materials LLC	Sparta	Hancock	B	17	319873	3684827	22.07	100.00	Conservativly assumed as precursor consumers			100.00
30300028	Bulk Chemical Services, LLC	Sandersville	Washington	B	17	332102	3648913	22.19	0.86	Conservativly assumed as precursor consumers			0.86
14100008	Aggregates USA (Sparta), LLC	Sparta	Hancock	SM	17	319878	3685009	22.25	38.60	Conservativly assumed as precursor consumers			38.60
900002	Fowler-Flemister Concrete Inc	Milledgeville	Baldwin	B	17	291772	3663483	23.40	100.00	Conservativly assumed as precursor consumers			100.00
16700002	Roche Manufacturing	Wrightsville	Johnson	B	17	339368	3622734	47.20	100.00	Conservativly assumed as precursor consumers			100.00
30100020	Ballard Contractors	Warrenton	Warrenton	B	17	348781	3697401	47.90	100.00	Conservativly assumed as precursor consumers			100.00
23700134	Hy-Lite Products Inc	Eatonton	Putnam	B	17	276756	3692522	48.29	100.00	Conservativly assumed as precursor consumers			100.00
31900002	Old Hickory Clay Company	Mcintyre	Wilkinson	SM	17	295535	3636376	33.30	14.00	Conservativly assumed as precursor consumers			14.00

Table D-21. MERP Inventory Sources

AIRS #	Facility Name	City	County	Classification	UTM Zone	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_x Estimated Emissions (tpy)	List of Permit or Permit Amendment After October 2010	Date of Permit or Permit Amendment Issued	Description of Project	Impact on NOx Emissions? (tpy)
31900028	North American Container Corporation	Mcintyre	Wilkinson	B	17	296070	3635306	33.86	100.00	Conservativly assumed as precursor consumers			100.00
31900003	Covia Holdings Corp	Mcintyre	Wilkinson	SM	17	294527	3635912	34.27	43.80	Conservativly assumed as precursor consumers			43.80
31900021	Active Minerals International, LLC	Gordon	Wilkinson	SM	17	283919	3641776	37.93	60.60	Conservativly assumed as precursor consumers			60.60
900038	Union Hill Church Road MSW Landfill	Gordon	Baldwin	B	17	279874	3647123	38.82	100.00	Conservativly assumed as precursor consumers			100.00
												Total	**1,698.71**

Table D-22. Initial Inventory Source List for Regional Source Inventory

No.	Facility Name	AIRS #	Street Address	City	Zip Code	County	SIC	UTM Zone	UTM E (m)	UTM N (m)	Revised UTM Based on Google Earth UTM E (m)	Revised UTM Based on Google Earth UTM N (m)	Distance to Facility (km)	Exclusion (Yes/No)	Exclusion Reason
1	Fowler-Flemister Concrete Inc	900002	711 N. Wilkinson St.	Milledgeville	31061	Baldwin	3273	17	291759.0	3663364.0	291772.0	3663483.4	23.40	No	--
2	T & S Hardwoods Inc	900004	293 Harrisburg Rd.	Milledgeville	31061	Baldwin	2421	17	290716.0	3659644.0			24.73	Yes	No air permit found on Georgia Air Permit Search Engine
3	Central State Hospital	900019	Vinson Highway & Broad Street	Milledgeville	31062	Baldwin	8063	17	292823.0	3658572.0	319873.4	3684826.6	22.07	No	--
4	Triumph Aerostructures, LLC - Vought Aircraft Division	900031	90 Hwy 22 West	Milledgeville	31061	Baldwin	3728	17	286579.0	3663070.0	286579.0	3663070.0	28.60	No	--
5	Chem-Tex Inc	900034	70 Ga Hwy 22 West	Milledgeville	31061	Baldwin	2843	17	284986.0	3662471.0			30.20	Yes	No air permit found on Georgia Air Permit Search Engine
6	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	900035	180 J M Walker Rd, Ne	Milledgeville	31061	Baldwin	4922	17	308127.0	3660004.0	308127.0	3660004.0	7.77	No	--
7	Union Hill Church Road MSW Landfill	900038	154 Union Hill Church Road	Gordon	31031	Baldwin	4953	17	279933.0	3647639.0	279874.4	3647122.8	38.82	No	--
8	Mohawk Industries Inc	900041	120 Barnet Drive NW	Milledgeville	31061	Baldwin	2281	17	289235.0	3665031.0			26.00	Yes	No air permit found on Georgia Air Permit Search Engine
9	Rath Refractories	900044	290 Industrial Park Drive	Milledgeville	31061	Baldwin	3297	17	286697.0	3663830.0	286290.7	3663586.7	28.89	No	--
10	Baldwin Body Shop, Inc.	900045	121 W. Screven Street	Milledgeville	31061	Baldwin	7532	17	292216.0	3661764.0			23.01	Yes	Automotive shop - No NOx source expected
11	C&S Body Shop	900046	1050 S. Jefferson St.	Milledgeville	31061	Baldwin	7532	17	292659.0	3661064.0			22.62	Yes	Automotive shop - No NOx source expected
12	City of Milledgeville WPCP	900047	211 Highview Road	Milledgeville	31061	Baldwin	4952	17	295014.0	3658633.0			20.69	Yes	No air permit found on Georgia Air Permit Search Engine
13	James Baugh WTP	900048	318 Barrows Ferry Rd	Milledgeville	31061	Baldwin	4971	17	293515.0	3665044.0			21.73	Yes	No air permit found on Georgia Air Permit Search Engine
14	Lamar Ham WTP	900049	520 East Montgomery St.	Milledgeville	31061	Baldwin	4971	17	292877.0	3663116.0			22.30	Yes	No air permit found on Georgia Air Permit Search Engine
15	Paint Medics, Inc.	13300021	1031 Cloudland Ct.	Greensboro	30642	Greene	7532	17	294444.0	3704862.0			46.48	Yes	Automotive shop - No NOx source expected
16	Edwards Lumber Co Inc	14100001	Drwr D	Sparta	31087	Hancock	2421	17	315920.0	3683565.0			20.31	Yes	No air permit found on Georgia Air Permit Search Engine
17	Corridor Materials LLC	14100002	14674 Highway 16	Sparta	31087	Hancock	1423	17	315920.0	3683565.0	319873.4	3684826.6	22.07	No	--
18	Sparta Furniture Manu	14100006	401 Hamilton Box 400	Sparta	31087	Hancock	2511	17	316597.0	3684023.0			20.81	Yes	No air permit found on Georgia Air Permit Search Engine
19	Hanson Aggregates LLC - Sparta Quarry	14100007	1554 Shoals Rd.	Sparta	31087	Hancock	1423	17	337510.0	3685044.0			31.20	Yes	SM Exempt source
20	Aggregates USA (Sparta), LLC	14100008	14674 Highway 16	Sparta	31087	Hancock	1423	17	319878.0	3685009.0	319878.0	3685009.0	22.25	No	--
21	Pittman Construction Company	14100009	2403 Shoals Road	Sparta	31087	Hancock	2951	17	323114.0	3681120.0	322527.4	3681161.9	19.35	No	--
22	Stapleton Gin Co	16300002	Easy Street	Stapleton	30823	Jefferson	724	17	363368.0	3676056.0			49.86	Yes	No air permit found on Georgia Air Permit Search Engine
23	Coastal Processing LLC	16300039	1670 Forstmann Road	Louisville	30434	Jefferson	2015	17	363928.0	3652987.0			49.82	Yes	No air permit found on Georgia Air Permit Search Engine
24	Roche Manufacturing	16700002	411 East Court Street	Wrightsville	31096	Johnson		17	339367.7	3622734.1	339367.7	3622734.1	47.20	No	--
25	Wrightsville Lumber Co	16700006	Off Ga 15 & Ga 78 N	Wrightsville	31096	Johnson	2421	17	338864.0	3622706.0			46.97	Yes	No air permit found on Georgia Air Permit Search Engine
26	Hallman Wood Products	23700003	Harmony Road	Eatonton	31024	Putnam	2421	17	286117.0	3703864.0			49.93	Yes	No air permit found on Georgia Air Permit Search Engine
27	Fowler-Flemister Concrete Inc	23700009	114 Sammons Pkwy	Eatonton	31024	Putnam	3273	17	286810.0	3691747.0			40.20	Yes	Facility does not show up on Google Earch
28	Interfor U.S. Inc. - Eatonton Sawmill	23700010	370 Dennis Station Road SW	Eatonton	31024	Putnam	2421	17	280106.0	3680554.0	280106.0	3680554.0	39.10	No	--
29	Eatonton Cooperative Feed Co Inc	23700011	504 South Jefferson Street	Eatonton	31024	Putnam	2048	17	277973.0	3689396.0			45.46	Yes	No air permit found on Georgia Air Permit Search Engine
30	Alonan Manufacturing	23700124	601 Oak Street	Eatonton	31024	Putnam	3469	17	277383.0	3689106.0			45.78	Yes	No air permit found on Georgia Air Permit Search Engine
31	Gro Tec, Inc.	23700125	635 Madison Road, PO Box 4327	Eatonton	31024	Putnam	2875	17	277677.0	3690038.0	277118.1	3691720.3	47.52	No	--
32	Tech 2100 Inc	23700126	100.5 Ind. Blvd.	Eatonton	31024	Putnam	3088	17	277993.0	3687371.0			44.31	Yes	No air permit found on Georgia Air Permit Search Engine
33	Horton Vans Inc	23700132	130 Coleman Drive	Eatonton	31024	Putnam	3792	17	277577.0	3687278.0			44.61	Yes	SM Exempt source
34	Hy-Lite Products Inc	23700134	117 Sara Lee Dr.	Eatonton	31024	Putnam		17	276755.8	3692521.9	276755.8	3692521.9	48.29	No	--
35	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	30100003	331 Thomson Hwy, NE	Warrenton	30828	Warren	2421	17	346925.0	3697998.0	346925.0	3697998.0	47.06	No	--
36	Martin Marietta Aggregates	30100005	1471 Quaker Road	Warrenton	30828	Warren	1423	17	345411.0	3697710.0			45.83	Yes	SM Exempt source
37	Jebco, Inc.	30100010	500 Mayfield Rd	Warrenton	30828	Warren	3479	17	343658.0	3697527.0	343862.6	3697257.3	44.48	No	--
38	Piedmont Wood Pellet Warrenton, LLC	30100018	Quaker Road	Warrenton	30828	Warren	2499	17	351168.0	3693160.0			46.79	Yes	No air permit found on Georgia Air Permit Search Engine
39	Ballard Contractors	30100020	192-198 E. Warrenton Rd.	Warrenton	30628	Warrenton		17	348781.0	3697401.4	348781.0	3697401.4	47.90	No	--
40	IMERYS Sandersville Calcine Plant	30300004	618 Kaolin Road	Sandersville	31082	Washington	3295	17	329651.0	3648799.0	329651.0	3648799.0	20.46	No	--
41	Kent-Tenn Clay (Plts 51 & 52)	30300005	Kaolin Road	Sandersville	31082	Washington	3295	17	329507.0	3648668.0	329507.0	3648668.0	20.46	No	--
42	Thiele Kaolin Company - Sandersville Plant	30300006	520 Kaolin Road	Sandersville	31082	Washington	3295	17	329823.0	3648934.0	330074.0	3649291.5	20.43	No	--
43	IMERYS Deepstep Road Plant	30300008	4062 Deepstep Road	Sandersville	31082	Washington	3295	17	324393.0	3654774.0	324420.3	3655596.4	12.01	No	--
44	Burgess Pigment Company	30300009	525 Beck Blvd.	Sandersville	31082	Washington	3295	17	329959.0	3649142	329531.5	3650049.0	19.51	No	--
45	Strickland Concrete Products	30300011	122 N. Sunset Blvd	Sandersville	31082	Washington	2879	17	330773.0	3650665.0			20.05	Yes	No air permit found on Georgia Air Permit Search Engine
46	Evans Adhesive Corp	30300018	723 Loos Drive	Sandersville	31082	Washington	2891	17	330022.0	3649245.0			20.42	Yes	No air permit found on Georgia Air Permit Search Engine
47	Smith-Sheppard Concre	30300020	S. Harris St	Sandersville	31082	Washington	3273	17	331002.0	3649652.0			20.88	Yes	No air permit found on Georgia Air Permit Search Engine
48	Kent-Tenn Clay (Plt 53)	30300021	3597 Deepstep Road	Sandersville	31082	Washington	3295	17	325077.0	3654428.0	325077.0	3654428.0	13.27	No	--
49	Lapp Insulator Company	30300023	Kaolin Road	Sandersville	31082	Washington	3264	17	329504.0	3648662.0			20.46	Yes	No air permit found on Georgia Air Permit Search Engine
50	Tennille Veneer Inc	30300025	Zeta Street	Tennille	31089	Washington	2436	17	330597.0	3644988.0			23.91	Yes	No air permit found on Georgia Air Permit Search Engine
51	Bulk Chemical Services, LLC	30300028	736 Industrial Drive	Sandersville	31082	Washington	2869	17	332102.0	3648913.0	332102.0	3648913.0	22.19	No	--
52	Brite Co Inc	30300030	Industrial Drive	Sandersville	31082	Washington	2819	17	331444.0	3648939.0			21.68	Yes	No air permit found on Georgia Air Permit Search Engine
53	KaMin - Sandersville	30300035	530 Beck Blvd	Sandersville	31082	Washington	3295	17	329959.0	3649142.0	329959.0	3649142.0	20.45	No	--
54	Washington County Power, LLC	30300039	1177 County Line Road	Sandersville	31082	Washington	4911	17	315139	3663375			0.12	No	The facility itself
55	AL Sandersville	30300040	1600 Mills Lindsey School Road	Warthen	31094	Washington	4911	17	326387.0	3666032.0	326387.0	3666032.0	11.55	No	--
56	Georgia Industrial Minerals, Inc.	30300046	1132 Veal Rd	Sandersville	31082	Washington	3295	17	316544.0	3655893.0	317008.3	3656707.4	6.81	No	--
57	Trojan Battery Company, LLC	30300047	3012 George J Lyons Pkwy West	Sandersville	31082	Washington	3691	17	328356.0	3653199.0	328356.0	3653199.0	16.58	No	--
58	Plant Washington	30300051	Mayview Road	Sandersville	31082	Washington	4911	17	332530.0	3653638.0			19.85	Yes	Facility does not show up on Google Earch
59	GBF Sandersville 1	30300055	1103 South Harris Street	Sandersville	31082	Washington	2499	17	330919.0	3648418.0			21.64	Yes	Facility does not show up on Google Earch
60	GBF Sandersville 2	30300056	2746 Deepstep Road	Sandersville	31082	Washington	2499	17	326231.0	3653715.0			14.61	Yes	Facility does not show up on Google Earch
61	ARI Railcar Services, LLC	30300057	754 Joiner Road	Tennille	31089	Washington	4789	17	329809.0	3644912.0	329809.0	3644912.0	23.47	No	--
62	County Line Power, LLC	30300058	1177 County Line Road	Sandersville	31082	Washington	4911	17	315117.0	3662937.0			0.33	Yes	No air permit found on Georgia Air Permit Search Engine
63	Old Hickory Clay Company	31900002	159 Railroad St.	Mcintyre	31054	Wilkinson	3295	17	295337.0	3636288.0	295534.7	3636376.1	33.30	No	--
64	Covia Holdings Corp	31900003	107 Macon Rd[1]	Mcintyre	31054	Wilkinson	3295	17	292829.0	3636299.0	294526.6	3635912.3	34.27	No	--

Table D-22. Initial Inventory Source List for Regional Source Inventory

No.	Facility Name	AIRS #	Street Address	City	Zip Code	County	SIC	UTM Zone	UTM E (m)	UTM N (m)	Revised UTM Based on Google Earth UTM E (m)	Revised UTM Based on Google Earth UTM N (m)	Distance to Facility (km)	Exclusion (Yes/No)	Exclusion Reason
65	BASF Corporation, Gordon Plant	31900004	Hwy. 18 Spur	Gordon	31031	Wilkinson	3295	17	281193.0	3640502.0	281193.0	3640502.0	40.90	No	--
66	BASF Corporation, Edgar Plant	31900009	1277 Dedrick Road	Mcintyre	31054	Wilkinson	3295	17	292936.0	3636304.0	292936.0	3636304.0	34.95	No	--
67	BASF Corporation, Toddville Plant	31900013	1277 Dedrick Road	Mcintyre	31054	Wilkinson	3295	17	291108.0	3637205.0	291108.0	3637205.0	35.47	No	--
68	New Holland Tire Co Inc	31900014	US Hwy 82 East	Toomsboro	31090	Wilkinson	2421	17	305303.0	3634038.0			30.85	Yes	No air permit found on Georgia Air Permit Search Engine
69	Culpepper Wood Produc	31900015	Old McIntyre Rd	Irwinton	31042	Wilkinson	2448	17	296540.0	3632460.0			36.00	Yes	No air permit found on Georgia Air Permit Search Engine
70	Fountain Pallet Co Inc	31900016	Rte 1	Mcintyre	31054	Wilkinson	2448	17	292504.0	3636973.0			34.72	Yes	No air permit found on Georgia Air Permit Search Engine
71	Bloodworth H F	31900019	Rte 1	Mcintyre	31054	Wilkinson	2421	17	292504.0	3636973.0			34.72	Yes	No air permit found on Georgia Air Permit Search Engine
72	Elite Lab Inc	31900020	Tremon Street	Gordon	31031	Wilkinson	2819	17	280728.0	3640486.0			41.30	Yes	No air permit found on Georgia Air Permit Search Engine
73	Active Minerals International, LLC	31900021	121 Milledgeville Rd	Gordon	31031	Wilkinson	3295	17	283919.0	3641776.0	283919.0	3641776.0	37.93	No	--
74	Rescar Companies	31900023	107 Ball Park Road	Gordon	31031	Wilkinson	4789	17	303620	3634184			31.29	Yes	SM Exempt source
75	Carbo Ceramics, Inc. - McIntyre Plant	31900027	2295 Wriley Rd	Mcintyre	31054	Wilkinson	3295	17	297617.0	3636464.0	297617.0	3636464.0	32.04	No	--
76	North American Container Corporation	31900028	226 Wilco Road	Mcintyre	31054	Wilkinson	2448	17	296468.0	3635330.0	296069.8	3635305.8	33.86	No	--
77	Carbo Ceramics, Inc. - Toomsboro Plant	31900029	1880 Dent Rd	Toomsboro	31090	Wilkinson	3295	17	300929.0	3636634.0	300929.0	3636634.0	30.20	No	--
78	PT Power Project	31900030	Brannan Road	Toomsboro	31090	Wilkinson	4911	17	303620.0	3634184.0			31.29	Yes	Facility does not show up on Google Earch
79	Dennard's Body Shop	31900032	154 Macon Road	Gordon	31031	Wilkinson	7532	17	281393.0	3640262.0			40.87	Yes	--

1. Covia Holdings Corp is named as "Unimin Corp" in https://psd.gaepd.org/inventory/ .

Table D-23. Refined Inventory Source List for Regional Source Inventory

No.	Facility Name	Source Type	AIRS #	Street Address	City	Zip Code	County	Zone 17N UTM E (m)	Zone 17N UTM N (m)	Distance to Facility (km)	NOx Emissions (lb/hr)	NOx Emissions (tpy)	$PM_{2.5}$ Emissions (lb/hr)	$PM_{2.5}$ Emissions (tpy)	Reference of Emission Rates
1	Fowler-Flemister Concrete Inc	B	900002	711 N. Wilkinson St.	Milledgeville	31061	Baldwin	291772	3663483	23.40	N/A	100.00	N/A	100.00	See Note 1
2	Central State Hospital	A	900019	Vinson Highway & Broad Street	Milledgeville	31062	Baldwin	319873	3684827	22.07	14.70	64.39	22.90	100.30	https://psd.gaepd.org/inventory/
3	Triumph Aerostructures, LLC - Vought Aircraft Division	A	900031	90 Hwy 22 West	Milledgeville	31061	Baldwin	286579	3663070	28.60	6.96	30.48	0.54	2.37	https://psd.gaepd.org/inventory/
4	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	A	900035	180 J M Walker Rd, Ne	Milledgeville	31061	Baldwin	308127	3660004	7.77	93.62	410.06	4.45	19.49	https://psd.gaepd.org/inventory/
5	Union Hill Church Road MSW Landfill	B	900038	154 Union Hill Church Road	Gordon	31031	Baldwin	279874	3647123	38.82	N/A	100.00	N/A	100.00	See Note 1
6	Rath Refractories	SM	900044	290 Industrial Park Drive	Milledgeville	31061	Baldwin	286291	3663587	28.89	N/A	99.00	N/A	4.44	https://psd.gaepd.org/inventory/
7	Corridor Materials LLC	B	14100002	14674 Highway 16	Sparta	31087	Hancock	319873	3684827	22.07	N/A	100.00	N/A	100.00	See Note 1
8	Aggregates USA (Sparta), LLC	SM	14100008	14674 Highway 16	Sparta	31087	Hancock	319878	3685009	22.25	N/A	38.60	N/A	7.39	https://psd.gaepd.org/inventory/
9	Pittman Construction Company	SM	14100009	2403 Shoals Road	Sparta	31087	Hancock	322527	3681162	19.35	N/A	16.50	N/A	8.64	https://psd.gaepd.org/inventory/
10	Roche Manufacturing	B	16700002	411 East Court Street	Wrightsville	31096	Johnson	339368	3622734	47.20	N/A	100.00	N/A	100.00	See Note 1
11	Interfor U.S. Inc. - Eatonton Sawmill	A	23700010	370 Dennis Station Road SW	Eatonton	31024	Putnam	280106	3680554	39.10	20.24	88.65	29.05	127.24	https://psd.gaepd.org/inventory/
12	Gro Tec, Inc.	B	23700125	635 Madison Road, PO Box 4327	Eatonton	31024	Putnam	277118	3691720	47.52	N/A	--	N/A	70.61	Permit 2875-237-0125-B-01-0 Narrative
13	Hy-Lite Products Inc	B	23700134	117 Sara Lee Dr.	Eatonton	31024	Putnam	276756	3692522	48.29	N/A	100.00	N/A	100.00	See Note 1
14	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	A	30100003	331 Thomson Hwy, NE	Warrenton	30828	Warren	346925	3697998	47.06	9.46	41.43	11.42	50.02	https://psd.gaepd.org/inventory/
15	Jebco, Inc.	SM	30100010	500 Mayfield Rd	Warrenton	30828	Warren	343863	3697257	44.48	N/A	100.00	N/A	100.00	See Note 1
16	Ballard Contractors	B	30100020	192-198 E. Warrenton Rd.	Warrenton	30628	Warrenton	348781	3697401	47.90	N/A	100.00	N/A	100.00	See Note 1
17	IMERYS Sandersville Calcine Plant	A	30300004	618 Kaolin Road	Sandersville	31082	Washington	329651	3648799	20.46	26.13	114.45	36.16	158.38	https://psd.gaepd.org/inventory/
18	Kent-Tenn Clay (Plts 51 & 52)	SM	30300005	Kaolin Road	Sandersville	31082	Washington	329507	3648668	20.46	N/A	11.30	N/A	95.00	https://psd.gaepd.org/inventory/
19	Thiele Kaolin Company - Sandersville Plant	A	30300006	520 Kaolin Road	Sandersville	31082	Washington	330074	3649292	20.43	46.40	203.23	69.36	303.80	https://psd.gaepd.org/inventory/
20	IMERYS Deepstep Road Plant	A	30300008	4062 Deepstep Road	Sandersville	31082	Washington	324420	3655596	12.01	39.71	173.93	134.11	587.40	https://psd.gaepd.org/inventory/
21	Burgess Pigment Company	A	30300009	525 Beck Blvd.	Sandersville	31082	Washington	329532	3650049	19.51	17.43	76.34	90.81	397.75	https://psd.gaepd.org/inventory/
22	Kent-Tenn Clay (Plt 53)	SM	30300021	3597 Deepstep Road	Sandersville	31082	Washington	325077	3654428	13.27	N/A	25.60	N/A	94.50	https://psd.gaepd.org/inventory/
23	Bulk Chemical Services, LLC	B	30300028	736 Industrial Drive	Sandersville	31082	Washington	332102	3648913	22.19	N/A	0.86	N/A	--	Permit 2869-303-0028-B-02-0 Narrative
24	KaMin - Sandersville	A	30300035	530 Beck Blvd	Sandersville	31082	Washington	329959	3649142	20.45	28.54	125.01	26.35	115.41	https://psd.gaepd.org/inventory/
25	AL Sandersville	A	30300040	1600 Mills Lindsey School Road	Warthen	31094	Washington	326387	3666032	11.55	165.60	725.33	26.48	115.98	https://psd.gaepd.org/inventory/
26	Georgia Industrial Minerals, Inc.	B	30300046	1132 Veal Rd	Sandersville	31082	Washington	317008	3656707	6.81	N/A	100.00	N/A	100.00	See Note 1
27	Trojan Battery Company, LLC	SM	30300047	3012 George J Lyons Pkwy West	Sandersville	31082	Washington	328356	3653199	16.58	N/A	6.02	N/A	18.60	https://psd.gaepd.org/inventory/
28	ARI Railcar Services, LLC	SM	30300057	754 Joiner Road	Tennille	31089	Washington	329809	3644912	23.47	N/A	8.60	N/A	0.90	Permit 4789-303-0057-S-01-0 Narrative
29	Old Hickory Clay Company	SM	31900002	159 Railroad St.	Mcintyre	31054	Wilkinson	295535	3636376	33.30	N/A	14.00	N/A	81.20	https://psd.gaepd.org/inventory/
30	Covia Holdings Corp	SM	31900003	107 Macon Rd1	Mcintyre	31054	Wilkinson	294527	3635912	34.27	N/A	43.80	N/A	98.90	https://psd.gaepd.org/inventory/
31	BASF Corporation, Gordon Plant	A	31900004	Hwy. 18 Spur	Gordon	31031	Wilkinson	281193	3640502	40.90	N/A	184.00	N/A	646.54	TVR Application Submittal - 4/3/2019
32	BASF Corporation, Edgar Plant	A	31900009	1277 Dedrick Road	Mcintyre	31054	Wilkinson	292936	3636304	34.95	N/A	336.00	N/A	1,106.00	TVR Application Submittal - 8/8/2019
33	BASF Corporation, Toddville Plant	A	31900013	1277 Dedrick Road	Mcintyre	31054	Wilkinson	291108	3637205	35.47	N/A	173.00	N/A	389.00	TVR Application Submittal - 2/12/2019
34	Active Minerals International, LLC	SM	31900021	121 Milledgeville Rd	Gordon	31031	Wilkinson	283919	3641776	37.93	N/A	60.60	N/A	124.00	https://psd.gaepd.org/inventory/
35	Carbo Ceramics, Inc. - McIntyre Plant	A	31900027	2295 Wriley Rd	Mcintyre	31054	Wilkinson	297617	3636464	32.04	251.64	1,102.18	38.80	169.94	https://psd.gaepd.org/inventory/
36	North American Container Corporation	B	31900028	226 Wilco Road	Mcintyre	31054	Wilkinson	296070	3635306	33.86	N/A	100.00	N/A	100.00	See Note 1
37	Carbo Ceramics, Inc. - Toomsboro Plant	A	31900029	1880 Dent Rd	Toomsboro	31090	Wilkinson	300929	3636634	30.20	553.75	2,425.43	69.16	302.92	https://psd.gaepd.org/inventory/

1. No data available, PTE is conservatively assumed based on minor source status

Table D-24. Refined Inventory Source Cluster Emissions Calculation

AIRS #	Facility Name	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_X (tpy)	$PM_{2.5}$ (tpy)	900002 Fowler-Flemister Concrete Inc	900019 Central State Hospital	900031 Triumph Aerostructures, LLC - Vought Aircraft Division	900035 Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	900038 Union Hill Church Road MSW Landfill	900044 Rath Refractories	14100002 Corridor Materials LLC	14100008 Aggregates USA (Sparta), LLC	14100009 Pittman Construction Company	16700002 Roche Manufacturing	23700010 Interfor U.S. Inc. - Eatonton Sawmill	23700125 Gro Tec, Inc.	23700134 Hy-Lite Products Inc	30100003 GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	30100010 Jebco, Inc.	30100020 Ballard Contractors	30300004 IMERYS Sandersville Calcine Plant	30300005 Kent-Tenn Clay (Plts 51 & 52)	30300006 Thiele Kaolin Company - Sandersville Plant	30300008 IMERYS Deepstep Road Plant	30300009 Burgess Pigment Company	30300021 Kent-Tenn Clay (Plt 53)	30300028 Bulk Chemical Services, LLC	30300035 KaMin - Sandersville	30300040 AL Sandersville	30300046 Georgia Industrial Minerals, Inc.	30300047 Trojan Battery Company, LLC
						UTM E	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####
						UTM N	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####
						Distance to Facility (km)	23.4	22.1	28.6	7.8	38.8	28.9	22.1	22.2	19.3	47.2	39.1	47.5	48.3	47.1	44.5	47.9	20.5	20.5	20.4	12.0	19.5	13.3	22.2	20.4	11.5	6.8	16.6
						NO_X (tpy)	100.00	64.39	30.48	410.06	100.00	99.00	100.00	38.60	16.50	100.00	88.65	--	100.00	41.43	100.00	100.00	114.45	11.30	203.23	173.93	76.34	25.60	0.86	125.01	725.33	100.00	6.02
							100.00	100.30	2.37	19.49	100.00	4.44	100.00	7.39	8.64	100.00	127.24	70.61	100.00	50.02	100.00	100.00	158.38	95.00	303.80	587.40	397.75	94.50	--	115.41	115.98	100.00	18.60
900002	Fowler-Flemister Concrete Inc	291772.0	3663483.4	23.4	100.00	100.00	--	35.29	5.21	16.72	20.23	5.48	35.29	35.40	35.47	62.66	20.68	31.81	32.69	65.06	62.08	66.34	40.63	40.54	40.85	33.59	40.08	34.51	42.88	40.79	34.71	26.13	38.00
900019	Central State Hospital	319873.4	3684826.6	22.1	64.39	100.30	35.29	--	39.77	27.46	54.97	39.74	--	**0.18**	4.52	65.08	40.00	43.31	43.80	30.09	27.02	31.52	37.33	37.42	36.97	29.58	36.09	30.84	37.94	37.08	19.89	28.26	32.75
900031	Triumph Aerostructures, LLC - Vought Aircraft Division	286579.0	3663070.0	28.6	30.48	2.37	5.21	39.77	--	21.77	17.30	**0.59**	39.77	39.88	40.24	66.44	18.64	30.17	31.05	69.73	66.71	71.05	45.37	45.28	45.63	38.57	44.88	39.46	47.67	45.56	39.92	31.09	42.93
900035	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	308127.0	3660004.0	7.8	410.06	19.49	16.72	27.46	21.77	--	31.05	22.13	27.46	27.63	25.59	48.63	34.75	44.36	45.18	54.30	51.62	55.24	24.27	24.20	24.42	16.88	23.61	17.84	26.42	24.38	19.23	9.47	21.34
900038	Union Hill Church Road MSW Landfill	279874.4	3647122.8	38.8	100.00	100.00	20.23	54.97	17.30	31.05	--	17.67	54.97	55.10	54.57	64.30	33.43	44.68	45.51	84.17	81.29	85.30	49.80	49.66	50.25	45.34	49.74	45.79	52.26	50.13	50.21	38.35	48.86
900044	Rath Refractories	286290.7	3663586.7	28.9	99.00	4.44	5.48	39.74	**0.59**	22.13	17.67	--	39.74	39.84	40.27	66.98	18.06	29.59	30.47	69.72	66.70	71.05	45.81	45.72	46.06	38.96	45.31	39.85	48.10	46.00	40.17	31.48	43.33
14100002	Corridor Materials LLC	319873.4	3684826.6	22.1	100.00	100.00	35.29	--	39.77	27.46	54.97	39.74	--	**0.18**	4.52	65.08	40.00	43.31	43.80	30.09	27.02	31.52	37.33	37.42	36.97	29.58	36.09	30.84	37.94	37.08	19.89	28.26	32.75
14100008	Aggregates USA (Sparta), LLC	319878.0	3685009.0	22.2	38.60	7.39	35.40	**0.18**	39.88	27.63	55.10	39.84	**0.18**	--	4.67	65.25	40.02	43.28	43.77	30.00	26.93	31.45	37.51	37.60	37.14	29.76	36.27	31.02	38.11	37.26	20.06	28.45	32.92
14100009	Pittman Construction Company	322527.4	3681161.9	19.3	16.50	8.64	35.47	4.52	40.24	25.59	54.57	40.27	4.52	4.67	--	60.81	42.43	46.62	47.16	29.64	26.73	30.87	33.14	33.24	32.75	25.64	31.89	26.86	33.64	32.87	15.61	25.07	28.56
16700002	Roche Manufacturing	339367.7	3622734.1	47.2	100.00	100.00	62.66	65.08	66.44	48.63	64.30	66.98	65.08	65.25	60.81	--	82.80	92.92	93.76	75.64	74.66	75.26	27.82	27.75	28.14	36.10	29.03	34.77	27.17	28.03	45.20	40.67	32.39
23700010	Interfor U.S. Inc. - Eatonton Sawmill	280106.0	3680554.0	39.1	88.65	127.24	20.68	40.00	18.64	34.75	33.43	18.06	40.00	40.02	42.43	82.80	--	11.56	12.43	69.06	65.91	70.71	58.85	58.80	58.94	50.86	58.08	52.01	60.87	58.92	48.51	43.94	55.46
23700125	Gro Tec, Inc.	277118.1	3691720.3	47.5	--	70.61	31.81	43.31	30.17	44.36	44.68	29.59	43.31	43.28	46.62	92.92	11.56	--	**0.88**	70.09	66.97	71.89	67.84	67.81	67.86	59.52	66.96	60.75	69.68	67.86	55.56	53.08	64.10
23700134	Hy-Lite Products Inc	276755.8	3692521.9	48.3	100.00	100.00	32.69	43.80	31.05	45.18	45.51	30.47	43.80	43.77	47.16	93.76	12.43	**0.88**	--	70.38	67.27	72.19	68.63	68.60	68.64	60.29	67.74	61.53	70.46	68.65	56.26	53.88	64.88
30100003	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	346925.0	3697998.0	47.1	41.43	50.02	65.06	30.09	69.73	54.30	84.17	69.72	30.09	30.00	29.64	75.64	69.06	70.09	70.38	--	3.15	**1.95**	52.14	52.31	51.54	48.00	51.01	48.74	51.27	51.72	38.00	50.99	48.49
30100010	Jebco, Inc.	343862.6	3697257.3	44.5	100.00	100.00	62.08	27.02	66.71	51.62	81.29	66.70	27.02	26.93	26.73	74.66	65.91	66.97	67.27	3.15	--	4.92	50.50	50.67	49.91	45.97	49.34	46.77	49.75	50.08	35.78	48.64	46.71
30100020	Ballard Contractors	348781.0	3697401.4	47.9	100.00	100.00	66.34	31.52	71.05	55.24	85.30	71.05	31.52	31.45	30.87	75.26	70.71	71.89	72.19	**1.95**	4.92	--	52.23	52.41	51.62	48.38	51.12	49.08	51.28	51.80	38.54	51.63	48.69
30300004	IMERYS Sandersville Calcine Plant	329651.0	3648799.0	20.5	114.45	158.38	40.63	37.33	45.37	24.27	49.80	45.81	37.33	37.51	33.14	27.82	58.85	67.84	68.63	52.14	50.50	52.23	--	**0.19**	**0.65**	8.58	**1.26**	7.25	2.45	**0.46**	17.54	14.91	4.59
30300005	Kent-Tenn Clay (Plts 51 & 52)	329507.0	3648668.0	20.5	11.30	95.00	40.54	37.42	45.28	24.20	49.66	45.72	37.42	37.60	33.24	27.75	58.80	67.81	68.60	52.31	50.67	52.41	**0.19**	--	**0.84**	8.60	**1.38**	7.27	2.61	**0.65**	17.64	14.86	4.67
30300006	Thiele Kaolin Company - Sandersville Plant	330074.0	3649291.5	20.4	203.23	303.80	40.85	36.97	45.63	24.42	50.25	46.06	36.97	37.14	32.75	28.14	58.94	67.86	68.64	51.54	49.91	51.62	**0.65**	**0.84**	--	8.47	**0.93**	7.17	2.06	**0.19**	17.14	15.02	4.27
30300008	IMERYS Deepstep Road Plant	324420.3	3655596.4	12.0	173.93	587.40	33.59	29.58	38.57	16.88	45.34	38.96	29.58	29.76	25.64	36.10	50.86	59.52	60.29	48.00	45.97	48.38	8.58	8.60	8.47	--	7.54	**1.34**	10.18	8.51	10.62	7.49	4.61
30300009	Burgess Pigment Company	329531.5	3650049.0	19.5	76.34	397.75	40.08	36.09	44.88	23.61	49.74	45.31	36.09	36.27	31.89	29.03	58.08	66.96	67.74	51.01	49.34	51.12	**1.26**	**1.38**	**0.93**	7.54	--	6.25	2.81	**1.00**	16.29	14.18	3.36
30300021	Kent-Tenn Clay (Plt 53)	325077.0	3654428.0	13.3	25.60	94.50	34.51	30.84	39.46	17.84	45.79	39.85	30.84	31.02	26.86	34.77	52.01	60.75	61.53	48.74	46.77	49.08	7.25	7.27	7.17	**1.34**	6.25	--	8.93	7.20	11.68	8.38	3.50
30300028	Bulk Chemical Services, LLC	332102.0	3648913.0	22.2	0.86	--	42.88	37.94	47.67	26.42	52.26	48.10	37.94	38.11	33.64	27.17	60.87	69.68	70.46	51.27	49.75	51.28	2.45	2.61	2.06	10.18	2.81	8.93	--	2.16	18.05	16.99	5.69
30300035	KaMin - Sandersville	329959.0	3649142.0	20.4	125.01	115.41	40.79	37.08	45.56	24.38	50.13	46.00	37.08	37.26	32.87	28.03	58.92	67.86	68.65	51.72	50.08	51.80	**0.46**	**0.65**	**0.19**	8.51	**1.00**	7.20	2.16	--	17.26	15.00	4.36
30300040	AL Sandersville	326387.0	3666032.0	11.5	725.33	115.98	34.71	19.89	39.92	19.23	50.21	40.17	19.89	20.06	15.61	45.20	48.51	55.56	56.26	38.00	35.78	38.54	17.54	17.64	17.14	10.62	16.29	11.68	18.05	17.26	--	13.23	12.98
30300046	Georgia Industrial Minerals, Inc.	317008.3	3656707.4	6.8	100.00	100.00	26.13	28.26	31.09	9.47	38.35	31.48	28.26	28.45	25.07	40.67	43.94	53.08	53.88	50.99	48.64	51.63	14.91	14.86	15.02	7.49	14.18	8.38	16.99	15.00	13.23	--	11.88
30300047	Trojan Battery Company, LLC	328356.0	3653199.0	16.6	6.02	18.60	38.00	32.75	42.93	21.34	48.86	43.33	32.75	32.92	28.56	32.39	55.46	64.10	64.88	48.49	46.71	48.69	4.59	4.67	4.27	4.61	3.36	3.50	5.69	4.36	12.98	11.88	--
30300057	ARI Railcar Services, LLC	329809.0	3644912.0	23.5	8.60	0.90	42.33	41.13	46.89	26.42	49.98	47.36	41.13	41.31	36.97	24.15	61.16	70.48	71.28	55.78	54.20	55.81	3.89	3.77	4.39	11.97	5.14	10.63	4.61	4.23	21.40	17.41	8.41
31900002	Old Hickory Clay Company	295534.7	3636376.1	33.3	14.00	81.20	27.37	54.22	28.16	26.77	18.99	28.74	54.22	54.39	52.29	45.91	46.79	58.33	59.20	80.24	77.73	80.99	36.31	36.13	36.88	34.70	36.64	34.62	38.66	36.72	42.79	29.57	36.88
31900003	Covia Holdings Corp	294526.6	3635912.3	34.3	43.80	98.90	27.71	55.09	28.30	27.67	18.45	28.87	55.09	55.26	53.21	46.74	46.91	58.46	59.33	81.24	78.72	82.00	37.41	37.23	37.98	35.79	37.75	35.72	39.76	37.82	43.84	30.62	37.99
31900004	BASF Corporation, Gordon Plant	281193.0	3640502.0	40.9	184.00	646.54	25.30	58.83	23.20	33.25	6.75	23.64	58.83	58.97	57.98	60.83	40.07	51.38	52.21	87.33	84.55	88.35	49.16	49.00	49.66	45.79	49.27	46.04	51.60	49.53	51.91	39.31	48.84
31900009	BASF Corporation, Edgar Plant	292936.0	3636304.0	34.9	336.00	1,106.00	27.20	55.50	27.51	28.15	16.96	28.08	55.50	55.66	53.74	48.37	46.07	57.63	58.50	81.98	79.43	82.77	38.78	38.60	39.34	36.93	39.09	36.90	41.15	39.19	44.75	31.56	39.24
31900013	BASF Corporation, Toddville Plant	291108.0	3637205.0	35.5	173.00	389.00	26.29	55.64	26.26	28.45	14.99	26.82	55.64	55.79	54.03	50.38	44.72	56.28	57.15	82.53	79.93	83.37	40.25	40.07	40.80	38.05	40.51	38.09	42.63	40.64	45.56	32.42	40.54
31900021	Active Minerals International, LLC	283919.0	3641776.0	37.9	60.60	124.00	23.08	56.09	21.46	30.30	6.70	21.94	56.09	56.23	55.15	58.63	38.97	50.41	51.25	84.44	81.68	85.45	46.27	46.11	46.76	42.79	46.36	43.06	48.71	46.63	48.91	36.30	45.88
31900027	Carbo Ceramics, Inc. - McIntyre Plant	297617.0	3636464.0	32.0	1,102.18	169.94	27.64	53.24	28.80	25.78	20.70	29.39	53.24	53.41	51.17	43.95	47.44	58.94	59.81	78.85	76.38	79.57	34.33	34.15	34.90	32.93	34.69	32.81	36.66	34.74	41.26	28.03	35.00
31900028	North American Container Corporation	296069.8	3635305.8	33.9	100.00	100.00	28.50	54.94	29.34	27.48	20.05	29.92	54.94	55.11	52.94	45.09	47.98	59.51	60.39	80.73	78.24	81.45	36.19	36.01	36.77	34.86	36.57	34.74	38.52	36.60	43.17	29.94	36.91
31900029	Carbo Ceramics, Inc. - Toomsboro Plant	300929.0	3636634.0	30.2	2,425.43	302.92	28.37	51.78	30.08	24.45	23.52	30.67	51.78	51.95	49.49	40.87	48.61	60.01	60.89	76.69	74.29	77.35	31.19	31.01	31.77	30.19	31.59	30.00	33.50	31.61	38.89	25.72	32.04

Table D-24. Refined Inventory Source Cluster Emissions Calculation

AIRS #	Facility Name	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_X (tpy)	$PM_{2.5}$ (tpy)	30300057	31900002	31900003	31900004	31900009	31900013	31900021	31900027	31900028	31900029	Total Cluster NO_X (tpy)	Total Cluster $PM_{2.5}$ (tpy)	Total Sites in Cluster (Cluster Sites are Highlighted in Yellow)
						AIR #	30300057	31900002	31900003	31900004	31900009	31900013	31900021	31900027	31900028	31900029			
						Facility Name	ARI Railcar Services, LLC	Old Hickory Clay Company	Covia Holdings Corp	BASF Corporation, Gordon Plant	BASF Corporation, Edgar Plant	BASF Corporation, Toddville Plant	Active Minerals International, LLC	Carbo Ceramics, Inc. - McIntyre Plant	North American Container Corporation	Carbo Ceramics, Inc. - Toomsboro Plant			
						UTM E	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####			
						UTM N	######	######	######	######	######	######	######	######	######	######			
						Distance to Facility (km)	23.5	33.3	34.3	40.9	34.9	35.5	37.9	32.0	33.9	30.2			
						NO_X (tpy)	8.60	14.00	43.80	184.00	336.00	173.00	60.60	1102.18	100.00	2425.43			
						$PM_{2.5}$ (tpy)	0.90	81.20	98.90	646.54	1106.00	389.00	124.00	169.94	100.00	302.92			
900002	Fowler-Flemister Concrete Inc	291772.0	3663483.4	23.4	100.00	100.00	42.33	27.37	27.71	25.30	27.20	26.29	23.08	27.64	28.50	28.37	100.00	100.00	1
900019	Central State Hospital	319873.4	3684826.6	22.1	64.39	100.30	41.13	54.22	55.09	58.83	55.50	55.64	56.09	53.24	54.94	51.78	202.99	207.69	3
900031	Triumph Aerostructures, LLC - Vought Aircraft Division	286579.0	3663070.0	28.6	30.48	2.37	46.89	28.16	28.30	23.20	27.51	26.26	21.46	28.80	29.34	30.08	129.48	6.81	2
900035	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	308127.0	3660004.0	7.8	410.06	19.49	26.42	26.77	27.67	33.25	28.15	28.45	30.30	25.78	27.48	24.45	410.06	19.49	1
900038	Union Hill Church Road MSW Landfill	279874.4	3647122.8	38.8	100.00	100.00	49.98	18.99	18.45	6.75	16.96	14.99	6.70	20.70	20.05	23.52	100.00	100.00	1
900044	Rath Refractories	286290.7	3663586.7	28.9	99.00	4.44	47.36	28.74	28.87	23.64	28.08	26.82	21.94	29.39	29.92	30.67	129.48	6.81	2
14100002	Corridor Materials LLC	319873.4	3684826.6	22.1	100.00	100.00	41.13	54.22	55.09	58.83	55.50	55.64	56.09	53.24	54.94	51.78	202.99	207.69	3
14100008	Aggregates USA (Sparta), LLC	319878.0	3685009.0	22.2	38.60	7.39	41.31	54.39	55.26	58.97	55.66	55.79	56.23	53.41	55.11	51.95	202.99	207.69	3
14100009	Pittman Construction Company	322527.4	3681161.9	19.3	16.50	8.64	36.97	52.29	53.21	57.98	53.74	54.03	55.15	51.17	52.94	49.49	16.50	8.64	1
16700002	Roche Manufacturing	339367.7	3622734.1	47.2	100.00	100.00	24.15	45.91	46.74	60.83	48.37	50.38	58.63	43.95	45.09	40.87	100.00	100.00	1
23700010	Interfor U.S. Inc. - Eatonton Sawmill	280106.0	3680554.0	39.1	88.65	127.24	61.16	46.79	46.91	40.07	46.07	44.72	38.97	47.44	47.98	48.61	88.65	127.24	1
23700125	Gro Tec, Inc.	277118.1	3691720.3	47.5	--	70.61	70.48	58.33	58.46	51.38	57.63	56.28	50.41	58.94	59.51	60.01	100.00	170.61	2
23700134	Hy-Lite Products Inc	276755.8	3692521.9	48.3	100.00	100.00	71.28	59.20	59.33	52.21	58.50	57.15	51.25	59.81	60.39	60.89	100.00	170.61	2
30100003	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	346925.0	3697998.0	47.1	41.43	50.02	55.78	80.24	81.24	87.33	81.98	82.53	84.44	78.85	80.73	76.69	141.43	150.02	2
30100010	Jebco, Inc.	343862.6	3697257.3	44.5	100.00	100.00	54.20	77.73	78.72	84.55	79.43	79.93	81.68	76.38	78.24	74.29	100.00	100.00	1
30100020	Ballard Contractors	348781.0	3697401.4	47.9	100.00	100.00	55.81	80.99	82.00	88.35	82.77	83.37	85.45	79.57	81.45	77.35	141.43	150.02	2
30300004	IMERYS Sandersville Calcine Plant	329651.0	3648799.0	20.5	114.45	158.38	3.89	36.31	37.41	49.16	38.78	40.25	46.27	34.33	36.19	31.19	530.33	1,070.34	5
30300005	Kent-Tenn Clay (Plts 51 & 52)	329507.0	3648668.0	20.5	11.30	95.00	3.77	36.13	37.23	49.00	38.60	40.07	46.11	34.15	36.01	31.01	530.33	1,070.34	5
30300006	Thiele Kaolin Company - Sandersville Plant	330074.0	3649291.5	20.4	203.23	303.80	4.39	36.88	37.98	49.66	39.34	40.80	46.76	34.90	36.77	31.77	530.33	1,070.34	5
30300008	IMERYS Deepstep Road Plant	324420.3	3655596.4	12.0	173.93	587.40	11.97	34.70	35.79	45.79	36.93	38.05	42.79	32.93	34.86	30.19	199.53	681.90	2
30300009	Burgess Pigment Company	329531.5	3650049.0	19.5	76.34	397.75	5.14	36.64	37.75	49.27	39.09	40.51	46.36	34.69	36.57	31.59	530.33	1,070.34	5
30300021	Kent-Tenn Clay (Plt 53)	325077.0	3654428.0	13.3	25.60	94.50	10.63	34.62	35.72	46.04	36.90	38.09	43.06	32.81	34.74	30.00	199.53	681.90	2
30300028	Bulk Chemical Services, LLC	332102.0	3648913.0	22.2	0.86	--	4.61	38.66	39.76	51.60	41.15	42.63	48.71	36.66	38.52	33.50	0.86	0.00	1
30300035	KaMin - Sandersville	329959.0	3649142.0	20.4	125.01	115.41	4.23	36.72	37.82	49.53	39.19	40.64	46.63	34.74	36.60	31.61	530.33	1,070.34	5
30300040	AL Sandersville	326387.0	3666032.0	11.5	725.33	115.98	21.40	42.79	43.84	51.91	44.75	45.56	48.91	41.26	43.17	38.89	725.33	115.98	1
30300046	Georgia Industrial Minerals, Inc.	317008.3	3656707.4	6.8	100.00	100.00	17.41	29.57	30.62	39.31	31.56	32.42	36.30	28.03	29.94	25.72	100.00	100.00	1
30300047	Trojan Battery Company, LLC	328356.0	3653199.0	16.6	6.02	18.60	8.41	36.88	37.99	48.84	39.24	40.54	45.88	35.00	36.91	32.04	6.02	18.60	1
30300057	ARI Railcar Services, LLC	329809.0	3644912.0	23.5	8.60	0.90	--	35.32	36.41	48.82	37.86	39.46	46.00	33.28	35.08	30.04	8.60	0.90	1
31900002	Old Hickory Clay Company	295534.7	3636376.1	33.3	14.00	81.20	35.32	--	**1.11**	14.92	2.60	4.50	12.81	2.08	**1.20**	5.40	157.80	280.10	3
31900003	Covia Holdings Corp	294526.6	3635912.3	34.3	43.80	98.90	36.41	**1.11**	--	14.10	**1.64**	3.65	12.12	3.14	**1.66**	6.44	493.80	1,386.10	4
31900004	BASF Corporation, Gordon Plant	281193.0	3640502.0	40.9	184.00	646.54	48.82	14.92	14.10	--	12.47	10.45	3.01	16.91	15.76	20.11	184.00	646.54	1
31900009	BASF Corporation, Edgar Plant	292936.0	3636304.0	34.9	336.00	1,106.00	37.86	2.60	**1.64**	12.47	--	2.04	10.55	4.68	3.29	8.00	379.80	1,204.90	2
31900013	BASF Corporation, Toddville Plant	291108.0	3637205.0	35.5	173.00	389.00	39.46	4.50	3.65	10.45	2.04	--	8.52	6.55	5.31	9.84	173.00	389.00	1
31900021	Active Minerals International, LLC	283919.0	3641776.0	37.9	60.60	124.00	46.00	12.81	12.12	3.01	10.55	8.52	--	14.69	13.77	17.77	60.60	124.00	1
31900027	Carbo Ceramics, Inc. - McIntyre Plant	297617.0	3636464.0	32.0	1,102.18	169.94	33.28	2.08	3.14	16.91	4.68	6.55	14.69	--	**1.93**	3.32	1,202.18	269.94	2
31900028	North American Container Corporation	296069.8	3635305.8	33.9	100.00	100.00	35.08	**1.20**	**1.66**	15.76	3.29	5.31	13.77	**1.93**	--	5.04	1,259.98	450.04	4
31900029	Carbo Ceramics, Inc. - Toomsboro Plant	300929.0	3636634.0	30.2	2,425.43	302.92	30.04	5.40	6.44	20.11	8.00	9.84	17.77	3.32	5.04	--	2,425.43	302.92	1

Table D-25. NO_2 Regional Source Inventory - Georgia Major and Minor Source 20D Review

AIRS #	Facility Name	City	County	Classification	UTM Zone	UTM E (m)	UTM N (m)	Distance to Facility (km)	NO_X Estimated Emissions (tpy)	NO_X Cluster Emissions (tpy)	Within NO_X Impact Area?	NO_X 20D Value	Are Emissions Greater than NOX 20D Value?	Include in NO_X Inventory?	Notes
900019	Central State Hospital	Milledgeville	Baldwin	A	17	319873	3684827	22.07	64.39	202.99	Yes	N/A	N/A	Yes	--
900035	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	Milledgeville	Baldwin	A	17	308127	3660004	7.77	410.06	410.06	Yes	N/A	N/A	Yes	--
30300004	IMERYS Sandersville Calcine Plant	Sandersville	Washington	A	17	329651	3648799	20.46	114.45	530.33	Yes	N/A	N/A	Yes	--
30300006	Thiele Kaolin Company - Sandersville Plant	Sandersville	Washington	A	17	330074	3649292	20.43	203.23	530.33	Yes	N/A	N/A	Yes	--
30300008	IMERYS Deepstep Road Plant	Sandersville	Washington	A	17	324420	3655596	12.01	173.93	199.53	Yes	N/A	N/A	Yes	--
30300009	Burgess Pigment Company	Sandersville	Washington	A	17	329532	3650049	19.51	76.34	530.33	Yes	N/A	N/A	Yes	--
30300035	KaMin - Sandersville	Sandersville	Washington	A	17	329959	3649142	20.45	125.01	530.33	Yes	N/A	N/A	Yes	--
30300040	AL Sandersville	Warthen	Washington	A	17	326387	3666032	11.55	725.33	725.33	Yes	N/A	N/A	Yes	--
30300005	Kent-Tenn Clay (Plts 51 & 52)	Sandersville	Washington	SM	17	329507	3648668	20.46	11.30	530.33	Yes	N/A	N/A	Yes	--
30300021	Kent-Tenn Clay (Plt 53)	Sandersville	Washington	SM	17	325077	3654428	13.27	25.60	199.53	Yes	N/A	N/A	Yes	--
30300047	Trojan Battery Company, LLC	Sandersville	Washington	SM	17	328356	3653199	16.58	6.02	6.02	Yes	N/A	N/A	Yes	--
14100009	Pittman Construction Company	Sparta	Hancock	SM	17	322527	3681162	19.35	16.50	16.50	Yes	N/A	N/A	Yes	--
30300057	ARI Railcar Services, LLC	Tennille	Washington	SM	17	329809	3644912	23.47	8.60	8.60	Yes	N/A	N/A	Yes	--
900044	Rath Refractories	Milledgeville	Baldwin	SM	17	286291	3663587	28.89	99.00	129.48	Yes	N/A	N/A	Yes	--
30100010	Jebco, Inc.	Warrenton	Warren	SM	17	343863	3697257	44.48	100.00	100.00	Yes	N/A	N/A	Yes	--
31900009	BASF Corporation, Edgar Plant	Mcintyre	Wilkinson	A	17	292936	3636304	34.95	336.00	379.80	Yes	N/A	N/A	Yes	--
31900013	BASF Corporation, Toddville Plant	Mcintyre	Wilkinson	A	17	291108	3637205	35.47	173.00	173.00	Yes	N/A	N/A	Yes	--
31900004	BASF Corporation, Gordon Plant	Gordon	Wilkinson	A	17	281193	3640502	40.90	184.00	184.00	Yes	N/A	N/A	Yes	--
900031	Triumph Aerostructures, LLC - Vought Aircraft Division	Milledgeville	Baldwin	A	17	286579	3663070	28.60	30.48	129.48	Yes	N/A	N/A	Yes	--
31900029	Carbo Ceramics, Inc. - Toomsboro Plant	Toomsboro	Wilkinson	A	17	300929	3636634	30.20	2425.43	2,425.43	Yes	N/A	N/A	Yes	--
31900027	Carbo Ceramics, Inc. - McIntyre Plant	Mcintyre	Wilkinson	A	17	297617	3636464	32.04	1102.18	1,202.18	Yes	N/A	N/A	Yes	--
23700010	Interfor U.S. Inc. - Eatonton Sawmill	Eatonton	Putnam	A	17	280106	3680554	39.10	88.65	88.65	Yes	N/A	N/A	Yes	--
30100003	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	Warrenton	Warren	A	17	346925	3697998	47.06	41.43	141.43	Yes	N/A	N/A	Yes	--
30300046	Georgia Industrial Minerals, Inc.	Sandersville	Washington	B	17	317008	3656707	6.81	100.00	100.00	Yes	N/A	N/A	No	See Note 1
14100002	Corridor Materials LLC	Sparta	Hancock	B	17	319873	3684827	22.07	100.00	202.99	Yes	N/A	N/A	No	See Note 2
30300028	Bulk Chemical Services, LLC	Sandersville	Washington	B	17	332102	3648913	22.19	0.86	0.86	Yes	N/A	N/A	No	See Note 1
14100008	Aggregates USA (Sparta), LLC	Sparta	Hancock	SM	17	319878	3685009	22.25	38.60	202.99	Yes	N/A	N/A	No	See Note 2
900002	Fowler-Flemister Concrete Inc	Milledgeville	Baldwin	B	17	291772	3663483	23.40	100.00	100.00	Yes	N/A	N/A	No	See Note 1
16700002	Roche Manufacturing	Wrightsville	Johnson	B	17	339368	3622734	47.20	100.00	100.00	Yes	N/A	N/A	No	See Note 2
30100020	Ballard Contractors	Warrenton	Warrenton	B	17	348781	3697401	47.90	100.00	141.43	Yes	N/A	N/A	No	See Note 2
23700134	Hy-Lite Products Inc	Eatonton	Putnam	B	17	276756	3692522	48.29	100.00	100.00	Yes	N/A	N/A	No	See Note 2
31900002	Old Hickory Clay Company	Mcintyre	Wilkinson	SM	17	295535	3636376	33.30	14.00	157.80	Yes	N/A	N/A	No	See Note 1
31900028	North American Container Corporation	Mcintyre	Wilkinson	B	17	296070	3635306	33.86	100.00	1,259.98	Yes	N/A	N/A	No	See Note 1
31900003	Covia Holdings Corp	Mcintyre	Wilkinson	SM	17	294527	3635912	34.27	43.80	493.80	Yes	N/A	N/A	No	See Note 1
31900021	Active Minerals International, LLC	Gordon	Wilkinson	SM	17	283919	3641776	37.93	60.60	60.60	Yes	N/A	N/A	No	See Note 1
900038	Union Hill Church Road MSW Landfill	Gordon	Baldwin	B	17	279874	3647123	38.82	100.00	100.00	Yes	N/A	N/A	No	See Note 2
23700125	Gro Tec, Inc.	Eatonton	Putnam	B	17	277118	3691720	47.52	0.00	100.00	Yes	N/A	N/A	No	See Note 2

1. File review indicated a lack of any usable information for dispersion modeling.
2. File review indicated the site of interest was not a source of NO_X emissions, and the source was, therefore, removed from consideration.

Table D-26. $PM_{2.5}$ Regional Source Inventory - Georgia Major and Minor Source 20D Review

AIRS #	Facility Name	City	County	Classification	UTM Zone	UTM E (m)	UTM N (m)	Distance to Facility (km)	$PM_{2.5}$ Estimated Emissions (tpy)	$PM_{2.5}$ Cluster Emissions (tpy)	Within $PM_{2.5}$ Impact Area?	$PM_{2.5}$ 20D Value	Are Emissions Greater than $PM_{2.5}$ 20D Value?	Include in $PM_{2.5}$ Inventory?	Notes
900019	Central State Hospital	Milledgeville	Baldwin	A	17	319873	3684827	22.07	100.30	207.69	No	441.36	No	No	--
900035	Southern Natural Gas Company, L.L.C - Hall Gate Comp. Station	Milledgeville	Baldwin	A	17	308127	3660004	7.77	19.49	19.49	No	155.31	No	No	--
30300004	IMERYS Sandersville Calcine Plant	Sandersville	Washington	A	17	329651	3648799	20.46	158.38	1,070.34	No	409.29	Yes	Yes	--
30300006	Thiele Kaolin Company - Sandersville Plant	Sandersville	Washington	A	17	330074	3649292	20.43	303.80	1,070.34	No	408.52	Yes	Yes	--
30300008	IMERYS Deepstep Road Plant	Sandersville	Washington	A	17	324420	3655596	12.01	587.40	681.90	No	240.23	Yes	Yes	--
30300009	Burgess Pigment Company	Sandersville	Washington	A	17	329532	3650049	19.51	397.75	1,070.34	No	390.26	Yes	Yes	--
30300035	KaMin - Sandersville	Sandersville	Washington	A	17	329959	3649142	20.45	115.41	1,070.34	No	408.90	Yes	Yes	--
30300040	AL Sandersville	Warthen	Washington	A	17	326387	3666032	11.55	115.98	115.98	No	230.97	No	No	--
30300005	Kent-Tenn Clay (Plts 51 & 52)	Sandersville	Washington	SM	17	329507	3648668	20.46	95.00	1,070.34	No	409.12	Yes	Yes	--
30300021	Kent-Tenn Clay (Plt 53)	Sandersville	Washington	SM	17	325077	3654428	13.27	94.50	681.90	No	265.43	Yes	Yes	--
30300047	Trojan Battery Company, LLC	Sandersville	Washington	SM	17	328356	3653199	16.58	18.60	18.60	No	331.69	No	No	--
14100009	Pittman Construction Company	Sparta	Hancock	SM	17	322527	3681162	19.35	8.64	8.64	No	386.98	No	No	--
30300057	ARI Railcar Services, LLC	Tennille	Washington	SM	17	329809	3644912	23.47	0.90	0.90	No	469.45	No	No	--
900044	Rath Refractories	Milledgeville	Baldwin	SM	17	286291	3663587	28.89	4.44	6.81	No	577.72	No	No	--
30100010	Jebco, Inc.	Warrenton	Warren	SM	17	343863	3697257	44.48	100.00	100.00	No	889.61	No	No	--
31900009	BASF Corporation, Edgar Plant	Mcintyre	Wilkinson	A	17	292936	3636304	34.95	1106.00	1,204.90	No	698.98	Yes	Yes	--
31900013	BASF Corporation, Toddville Plant	Mcintyre	Wilkinson	A	17	291108	3637205	35.47	389.00	389.00	No	709.45	No	No	--
31900004	BASF Corporation, Gordon Plant	Gordon	Wilkinson	A	17	281193	3640502	40.90	646.54	646.54	No	818.02	No	No	--
900031	Triumph Aerostructures, LLC - Vought Aircraft Division	Milledgeville	Baldwin	A	17	286579	3663070	28.60	2.37	6.81	No	571.93	No	No	--
31900029	Carbo Ceramics, Inc. - Toomsboro Plant	Toomsboro	Wilkinson	A	17	300929	3636634	30.20	302.92	302.92	No	604.03	No	No	--
31900027	Carbo Ceramics, Inc. - McIntyre Plant	Mcintyre	Wilkinson	A	17	297617	3636464	32.04	169.94	269.94	No	640.79	No	No	--
23700010	Interfor U.S. Inc. - Eatonton Sawmill	Eatonton	Putnam	A	17	280106	3680554	39.10	127.24	127.24	No	781.99	No	No	--
30100003	GEORGIA-PACIFIC WOOD PRODUCTS LLC (WARRENTON)	Warrenton	Warren	A	17	346925	3697998	47.06	50.02	150.02	No	941.17	No	No	--
30300046	Georgia Industrial Minerals, Inc.	Sandersville	Washington	B	17	317008	3656707	6.81	100.00	100.00	No	136.17	No	No	--
14100002	Corridor Materials LLC	Sparta	Hancock	B	17	319873	3684827	22.07	100.00	207.69	No	441.36	No	No	--
30300028	Bulk Chemical Services, LLC	Sandersville	Washington	B	17	332102	3648913	22.19	0.00	0.00	No	443.84	No	No	--
14100008	Aggregates USA (Sparta), LLC	Sparta	Hancock	SM	17	319878	3685009	22.25	7.39	207.69	No	444.95	No	No	--
900002	Fowler-Flemister Concrete Inc	Milledgeville	Baldwin	B	17	291772	3663483	23.40	100.00	100.00	No	468.08	No	No	--
16700002	Roche Manufacturing	Wrightsville	Johnson	B	17	339368	3622734	47.20	100.00	100.00	No	944.03	No	No	--
30100020	Ballard Contractors	Warrenton	Warrenton	B	17	348781	3697401	47.90	100.00	150.02	No	958.06	No	No	--
23700134	Hy-Lite Products Inc	Eatonton	Putnam	B	17	276756	3692522	48.29	100.00	170.61	No	965.83	No	No	--
31900002	Old Hickory Clay Company	Mcintyre	Wilkinson	SM	17	295535	3636376	33.30	81.20	280.10	No	665.95	No	No	--
31900028	North American Container Corporation	Mcintyre	Wilkinson	B	17	296070	3635306	33.86	100.00	450.04	No	677.26	No	No	--
31900003	Covia Holdings Corp	Mcintyre	Wilkinson	SM	17	294527	3635912	34.27	98.90	1,386.10	No	685.42	Yes	No	See Note 1
31900021	Active Minerals International, LLC	Gordon	Wilkinson	SM	17	283919	3641776	37.93	124.00	124.00	No	758.60	No	No	--
900038	Union Hill Church Road MSW Landfill	Gordon	Baldwin	B	17	279874	3647123	38.82	100.00	100.00	No	776.32	No	No	--
23700125	Gro Tec, Inc.	Eatonton	Putnam	B	17	277118	3691720	47.52	70.61	170.61	No	950.38	No	No	--

1. File review indicated a lack of any usable information for dispersion modeling.

Table D-27. Regional Source Inventory Stack Parameters

AIRS	Name	Facility Description	Type	Address	County	Stack	Stack Description	Distance (km)	Zone	UTM E (m)	UTM N (m)	Elev (ft)	NO_X (lb/hr)	$PM_{2.5}$ (lb/hr)	Horizontal Stack? (Y/N)	Height (ft)	Temperature (F)	Velocity (ft/s)	Diameter (ft)
00900019	Central State Hospital	State Hospital	TV	Vinson Highway, GA R112 & Broad Street, Milledgeville, GA 31062	Baldwin	1	Boiler Number 1	22.91	17	292729	3658696	314	12.50	n/a	N	45.0	350	72.0	3.00
						2	Boiler Number 2	22.91	17	292721	3658692	316	12.50	n/a	N	45.0	350	72.0	3.00
						3	Boiler Number 3	22.93	17	292715	3658668	308	18.80	n/a	N	50.0	350	50.0	3.00
						4	Boiler Number 4	22.93	17	292708	3658665	309	18.80	n/a	N	50.0	350	50.0	3.00
						5	Hospital Boiler Number 1	21.96	17	294297	3656452	393	2.40	n/a	N	45.0	350	20.0	2.50
						6	Hospital Boiler Number 2	22.03	17	294210	3656499	410	2.40	n/a	N	45.0	350	20.0	2.50
00900035	SNG Hall Gate	Natural Gas Compressor Station	TV	180 J.M. Walker Road, NE, Milledgeville, Georgia 31061-9522	Baldwin	1	Compressor Engine No. 1	7.77	17	308127	3660004	445	42.90	n/a	N	35.7	710	91.5	2.40
						2	Compressor Engine No. 2	7.76	17	308136	3660008	444	42.90	n/a	N	35.7	710	91.5	2.40
						3	Compressor Engine No. 3	7.73	17	308161	3660023	442	7.82	n/a	N	40.0	858	57.2	3.00
30300004	IMERYS Sandersville Calcine Plant	Kaolin Processing	TV	618 Kaolin Road, Sandersville, GA 31082	Washington	1	Spray Dryer No. 3	20.39	17	329793	3649055	450	5.71	2.97	N	135	199	90.0	3.30
						2	Spray Dryer No. 4	20.34	17	329704	3649024	447	5.71	3.45	N	135	199	90.0	3.30
						3	Calciner No. 1	20.26	17	329612	3649054	448	2.85	1.04	N	140	160	37.4	2.00
						4	Calciner No. 2	20.35	17	329708	3649020	447	2.85	1.17	N	150	151	41.3	2.00
						5	Calciner No. 3	20.33	17	329708	3649048	445	2.85	1.17	N	150	151	41.3	2.00
						6	Calciner No. 4	20.34	17	329724	3649052	446	5.14	2.12	N	202	151	39.4	2.80
30300006	Thiele Kaolin Company - Sandersville Plant	Kaolin Processing	TV	520 Kaolin Road, Sandersville, Georgia 31082	Washington	1	Spray Dryer No. 1	20.19	17	329908	3649456	449	3.39	10.8	N	65.0	246	104	3.00
						2	Spray Dryer No. 2	20.19	17	329896	3649444	450	3.39	4.61	N	56.0	228	58.9	3.00
						3	Spray Dryer No. 3	20.17	17	329876	3649457	450	3.39	4.61	N	62.0	193	48.7	3.30
						4	Spray Dryer No. 4	20.19	17	329884	3649440	450	7.35	8.38	N	160	199	56.8	5.50
						5	Spray Dryer No. 5	20.23	17	329862	3649345	450	7.35	7.99	N	175	200	54.5	5.50
						6	Calciner No. 1/SD6	20.25	17	329882	3649349	451	5.43	1.11	N	175	125	28.3	5.00
						7	Calciner No. 2/SD7	20.25	17	329882	3649349	451	5.43	1.11	N	175	125	28.3	5.00
						8	New Boiler	20.16	17	329884	3649484	450	2.83	1.90	N	30.0	370	24.2	2.30
						9	Generator 1	20.24	17	329870	3649353	450	3.92	0.09	N	20.0	885	422	0.70
						10	Generator 2	20.24	17	329862	3649341	450	3.92	0.09	N	20.0	885	422	0.70
30300008	IMERYS Deepstep Road Plant	Kaolin Processing	TV	4062 Deepstep Road, Sandersville, Georgia 31082	Washington	1	Boiler No. 3	11.93	17	324435	3655740	424	4.27	0.59	N	36.0	350	42.9	2.00
						2	Boiler No. 4	11.94	17	324439	3655724	424	4.27	0.59	N	36.0	350	42.9	2.00
						3	Boiler No. 5	11.96	17	324463	3655736	423	4.98	0.68	N	36.0	350	42.9	2.00
						4	Spray Dryer No. 1	11.93	17	324423	3655724	424	4.77	21.0	N	81.0	145	52.0	3.50
						5	Spray Dryer No. 2	11.93	17	324419	3655725	424	5.46	30.6	N	90.0	145	51.0	5.20
						6	Spray Dryer No. 3	11.94	17	324431	3655724	424	5.46	30.6	N	90.0	145	51.0	5.20
						7	Spray Dryer No. 4	11.95	17	324443	3655720	424	5.46	30.6	N	90.0	145	51.0	5.20
						8	Apron Dryer (South Stack)	11.95	17	324443	3655720	424	1.68	3.72	N	30.0	220	37.1	3.00
						9	Apron Dryer (North Stack 1)	11.96	17	324447	3655712	424	1.68	3.72	N	30.0	293	34.9	2.50
						10	Apron Dryer (North Stack 2)	11.93	17	324435	3655740	424	1.68	3.72	N	30.0	293	34.9	2.50
30300009	Burgess Pigment Company	Kaolin Calcining	TV	525 Beck Boulevard, Sandersville, Georgia 31802-2903	Washington	1	No. 1B Calciner	20.45	17	329959	3649142	456	6.43	9.38	N	45.0	91.0	67.0	1.30
						2	No. 2 Calciner	20.45	17	329959	3649142	456	1.84	11.6	N	68.0	132	67.0	1.80
						3	No. 4 Calciner	20.45	17	329959	3649142	456	3.04	13.6	N	65.0	167	105	2.40
						4	No. 5 Calciner	20.45	17	329959	3649142	456	1.80	1.49	N	102	183	47.2	2.30
						5	No. 6 Calciner	20.45	17	329959	3649142	456	2.52	2.43	N	133	241	85.0	3.00
						6	No. 7 Calciner	20.45	17	329959	3649142	456	1.80	1.49	N	100	255	67.4	2.30
30300035	KaMin - Sandersville	Kaolin Processing	TV	530 Beck Blvd, Sandersville, Georgia 31082	Washington	1	Boiler No. 1	20.45	17	329959	3649142	456	1.80	0.48	N	25.0	300	38.0	1.70
						2	Boiler No. 2	20.45	17	329959	3649142	456	1.80	0.48	N	25.0	300	38.0	1.70
						3	Boiler No. 3	20.10	17	329562	3649221	438	2.40	0.48	N	30.0	300	38.0	1.70
						4	Boiler No. 5	20.45	17	329959	3649142	456	4.80	0.24	N	30.0	300	38.0	1.70
						5	Spray Dryer No. 1	19.91	17	329601	3649549	441	5.70	3.94	N	85.0	150	35.8	4.00
						6	Spray Dryer No. 2	20.45	17	329959	3649142	456	5.70	3.94	N	85.0	150	35.8	4.00
						7	Spray Dryer No. 5	20.03	17	329494	3649264	429	11.40	4.70	N	85.0	150	38.6	4.00
						8	Calciner No. 5	20.02	17	329458	3649241	434	5.10	2.38	N	120	180	42.7	2.70

Table D-27. Regional Source Inventory Stack Parameters

AIRS	Name	Facility Description	Type	Address	County	Stack	Stack Description	Distance (km)	Zone	UTM E (m)	UTM N (m)	Elev (ft)	NO_X (lb/hr)	$PM_{2.5}$ (lb/hr)	Horizontal Stack? (Y/N)	Height (ft)	Temperature (F)	Velocity (ft/s)	Diameter (ft)
30300040	AL Sandersville	Peak Power Generation	TV	1600 Mills Lindsey School Road, Warthen, Georgia 31094	Washington	1	Combustion Turbine 1	11.56	17	326431	3665915	455	193.00	n/a	N	65.0	999	139	15.0
						2	Combustion Turbine 2	11.52	17	326369	3665990	451	193.00	n/a	N	65.0	999	139	15.0
						3	Combustion Turbine 3	11.47	17	326288	3666096	437	193.00	n/a	N	65.0	999	139	15.0
						4	Combustion Turbine 4	11.55	17	326411	3665936	456	193.00	n/a	N	65.0	999	139	15.0
						5	Combustion Turbine 5	11.53	17	326388	3665968	457	193.00	n/a	N	65.0	999	139	15.0
						6	Combustion Turbine 6	11.51	17	326346.0	3666021	440	193.00	n/a	N	65.0	999	139	15.0
						7	Combustion Turbine 7	11.50	17	326330	3666043	436	193.00	n/a	N	65.0	999	139	15.0
						8	Combustion Turbine 8	11.48	17	326302	3666082	435	193.00	n/a	N	65.0	999	139	15.0
30300005	Kent-Tenn Clay (Plt 51/52)	Kaolin Processing	SM	514 Kaolin Road, Sandersville, GA 31082	Washington	1	Rotary Dryer, railcar loading (1)	20.26	17	330154.6	3649617.2	422	1.47	8.5	N	21	155	33.33	2.52
						2	Raymond Mill No. 1 (2A) and Raymond Mill No. 2 (2B)	20.26	17	330154.6	3649617.2	422	0.89	12	N	55	155	32.82	3.01
						3	Bulk Bag Loader, Dual Feed Bin Loading (3)	20.26	17	330154.6	3649617.2	422	--	0.171	N	56	200	16.67	1.25
30300021	Kent-Tenn Clay (Plt 53)	Kaolin Processing	SM	3597 Deepstep Road, Sandersville, GA 31082	Washington	1	Reject Silo No. 1	13.29	17	324889.0	3654188.1	435	--	0.212	Y	65	542	57.38	0.67
						2	Reject Silo No. 2	13.29	17	324889.0	3654188.1	435	--	0.17	Y	65	68	42.93	0.67
						3	Rotary Dryer	13.29	17	324889.0	3654188.1	435	1.28	2.204	Y	40	209	63.7	1.42
						4	No. 1 Raymond Mill with Dryer	13.29	17	324889.0	3654188.1	435	0.49	2.212	N	34	185	116.17	1.75
						5	No. 1 Raymond Mill Fugitives	13.29	17	324889.0	3654188.1	435	--	0.478	N	36	94	37.1	1.25
						6	Cage Mill Dryer	13.29	17	324889.0	3654188.1	435	1.32	2.564	N	8	147	59.11	2.73
						7	No. 2 Raymond Mill Feed Bin	13.29	17	324889.0	3654188.1	435	--	0.066	N	40	72	68.16	0.33
						8	No. 2 Raymond Mill with Dryer	13.29	17	324889.0	3654188.1	435	0.78	2.434	Y	45	166	97.01	2.08
						9	No. 2 Raymond Mill Rejects/Fugitives	13.29	17	324889.0	3654188.1	435	--	0.905	N	38	90	106.1	1
						10	Silos No. 4 and 5 Fugitives and Railcar Bulk Loadout No. 1	13.29	17	324889.0	3654188.1	435	--	0.269	N	33	91	24.16	1.17
						11	Silo No. 4	13.29	17	324889.0	3654188.1	435	--	0.337	N	52	72	85.94	0.67
						12	Silo No. 5	13.29	17	324889.0	3654188.1	435	--	0.374	N	52	72	95.49	0.67
						13	Silo No. 6, 7, 8, 9, and 10 and Railcar Bulk Loadout No. 2	13.29	17	324889.0	3654188.1	435	--	0.841	N	57	98	109.64	0.98
						14	Silo No. 11	13.29	17	324889.0	3654188.1	435	--	0.74957	N	88	72	141.86	0.67
						15	Silo No. 12 and Silos No. 11 and 12 Truck Loadout	13.29	17	324889.0	3654188.1	435	--	0.561	N	88	72	143.24	0.67
						16	Silo No. 13 and Silo No. 13 Truck Loadout	13.29	17	324889.0	3654188.1	435	--	0.65529	N	88	72	143.24	0.67
						17	Silo No. 15 and Silo No. 15 Railcar Loadout	13.29	17	324889.0	3654188.1	435	--	0.861	N	88	72	111.03	0.94
						18	50 Pound Baggers Palletizer	13.29	17	324889.0	3654188.1	435	--	0.536	N	43	104	123.45	0.73
						19	50 Pound Baggers	13.29	17	324889.0	3654188.1	435	--	0.308	N	43	108	71.84	0.73
						20	Bulk Baggers No. 1 and 2 and Low Residue Bagger	13.29	17	324889.0	3654188.1	435	--	0.839	N	15	73	78.98	1.11
						21	No. 3 Williams Mill with Dryer	13.29	17	324889.0	3654188.1	435	1.96	3.943	N	54	153	81.2	2.92
						22	Bulk Bagger No. 5	13.29	17	324889.0	3654188.1	435	--	0.12	N	15	73	78.98	1.11
						23	Bulk Bagger No. 6	13.29	17	324889.0	3654188.1	435	--	0.12	N	15	73	78.98	1.11
30300047	Trojan Batter Company, LLC	Battery Manufacturing	Minor	3012 George J Lyons Parkway West, Sandersville, GA 31082	Washington	1	Casting (8 Grid Casters, 1 Continuous Caster, 3 Melt Pots) Pasting (2 Flash Dry Ovens PL1-PL2)	16.50	17	328291.0	3653255.0	431	0.34	n/a	N	30	80	68.10	4.67
						2	Assembly (1 Melt Pot)	16.67	17	328408.0	3653122.0	434	0.34	n/a	N	30	80	68.1	4.67
						3	Curing (3 Curing Ovens C01- CO3)	16.52	17	328286.0	3653219.0	431	0.34	n/a	N	45	180	0.0033	340
						4	Curing (3 Curing Ovens C04-C06) Curing Oven 7 (C07)	16.53	17	328295.0	3653212.0	432	0.34	n/a	N	45	180	0.0033	340
14100009	Pittman Construction Company, LLC	Rock Quarry	Minor	3404 Shoals Road, Sparta, GA 31087	Hancock	1	Dryer Drum Mixer with 50 MMBtu/hr burner (No. 2 and No. 4 Fuel Oil)	19.85	17	323704.8	3681184.9	537	11.00	n/a	N	23.25	250	86.8	3.0833333
30300057	ARI Railcar Services, LLC	Railcar Repair	Minor	654 Joiner Road, Tennille, GA 31089	Washington	1	Boiler (NG at 8.4 MMBtu/hr)	23.33	17	329715.2	3645021.7	457	0.82	n/a	N	18	1500	31.97	1.50
						2	Flare	23.33	17	329715.2	3645021.7	457	0.05	n/a	N	16.6699	3623	0.0922	0.9101

Table D-27. Regional Source Inventory Stack Parameters

AIRS	Name	Facility Description	Type	Address	County	Stack	Stack Description	Distance (km)	Zone	UTM E (m)	UTM N (m)	Elev (ft)	NO_X (lb/hr)	$PM_{2.5}$ (lb/hr)	Horizontal Stack? (Y/N)	Height (ft)	Temperature (F)	Velocity (ft/s)	Diameter (ft)
						3	3 NG Direct Fired Heaters	23.33	17	329715.2	3645021.7	457	1.08	n/a	N	31.6699	100	8.8599	5.5801
00900044	Rath Refractories	Alumina	SM	290 Industrial Park	Baldwin	1	Dryer 1 & 2 (P016)	28.89	17	286289.3	3663629.6	358	0.10	n/a	N	33	302	43.53	1.33
		Refractory Brick		Drive, Milledgeville, GA		2	Kiln 1 & 2 (P017)	28.89	17	286289.3	3663629.6	358	15.01	n/a	N	60	620	36.07	3.33
		Manufacturing		31061		3	Kiln 3 (P023) Main Stack	28.89	17	286289.3	3663629.6	358	17.99	n/a	N	45	482	14.39	3.33
30100010	Jebco, Inc.	Coated Metal	SM	500 Mayfield Road,	Warren	1	Drying Oven 1	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	48	293	5.92	0.5
		Fabricated Items		Warrenton, GA 30828		2	Drying Oven 2	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	49	293	5.92	0.5
		Manufacturing				3	Drying Oven 3	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	49	293	5.92	0.5
						4	Drying Oven 4	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	48	293	5.92	0.5
						5	Drying Oven 5	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	33	410.93	6.6	0.5
						6	Drying Oven 6	44.61	17	343741.9	3697528.4	483	0.00	n/a	N	34	410.93	6.6	0.5
31900013	BASF Corporation,	Kaolin Clay	TV	1277 Dedrick Rd,	Wilkinson	1	2A Spray Dryer	35.34	17	291375.8	3637138.8	286	4.36	n/a	Y	75	210	101.0167	3.17
	Toddville Plant	Mining and		McIntyre, GA 31054		2	8B Boiler	35.72	17	290837.8	3637116.9	309	1.24	n/a	Y	20	65.1	56.5	1.5
		Processing				3	Toddville Boiler	35.36	17	291448.7	3637046.3	287	0.94	n/a	Y	20	65.1	28.2	1.67
						4	2B Spray Dryer	35.33	17	291388.9	3637137.5	285	4.36	n/a	Y	65	210	101.0167	3.17
						5	2C Spray Dryer	35.31	17	291402.3	3637151.6	284	4.36	n/a	Y	65	210	101.0167	3.17
						6	2D Spray Dryer	35.31	17	291482.3	3637082.2	285	7.00	n/a	Y	77	225	63.88333	4.17
						7	2F Spray Dryer	35.38	17	291495.1	3636978.8	292	11.43	n/a	Y	130	230	5221	5
						8	8D Boiler	35.71	17	290843.6	3637123.5	309	2.47	n/a	Y	23	65.1	56.5	1.5
						9	8C Boiler	35.73	17	290831.2	3637116.0	310	2.47	n/a	Y	19	65.1	56.5	1.5
						10	Sargent Dryer	35.31	17	291394.2	3637168.4	284	0.86	n/a	N	40	65.1	85.41667	4.51
31900009	BASF Corporation,	Kaolin Clay	TV	1277 Dedrick Rd,	Wilkinson	1	11A Calciner	34.98	17	292853.6	3636326.9	302	4.29	8.17	Y	150	170.6	53.13333	2
	Edgar Plant	Mining and		McIntyre, GA 31054		2	11F Calciner	35.11	17	292469.3	3636489.5	296	5.96	0.72	Y	200	158	63.18333	2.5
		Processing				3	11F Spray Dryer	35.10	17	292475.0	3636496.7	296	6.74	4.47	Y	198	250	184.35	2
						4	11G Calciner	35.15	17	292457.3	3636443.3	298	5.96	1.01	Y	198	65.1	106.3333	3
						5	11G Spray Dryer	35.15	17	292458.1	3636441.7	298	6.74	3.93	Y	197	250	40.4	4
						6	15A Calciner	34.96	17	292806.8	3636394.4	297	2.56	0.31	N	100	179.6	19.6	3
						7	15A Spray Dryer	34.96	17	292826.1	3636382.2	299	2.97	8.40	N	94	190	22.21667	4
						8	15B Calciner	34.98	17	292789.8	3636380.5	300	4.50	1.48	Y	120	159.8	112.1667	2.5
						9	15B Spray Dryer	35.02	17	292742.9	3636373.6	300	3.26	9.59	Y	75	250	64.11667	4
						10	Fluid Bed Dryer	35.11	17	292428.3	3636517.8	297	2.69	3.24	Y	160	65.1	46.45	3
						11	11B Calciner	35.04	17	292800.2	3636295.4	306	4.29	9.50	Y	75	165.2	39.28333	75
						12	#5 Filter Dryer	35.04	17	292871.5	3636243.5	303	4.18	12.99	Y	120	65.1	117.15	2.67
						13	11C Calciner	34.96	17	292853.7	3636354.2	300	2.56	7.51	Y	150	179.6	37.55	3
						14	1B Spray Dryer	35.02	17	292903.5	3636237.1	300	8.04	17.74	N	85	225	27.56667	5.5
						15	11E Calciner	35.06	17	292775.6	3636297.3	307	2.88	6.39E-07	N	115	154.4	52.75	2.5
						16	11D Calciner	34.92	17	292909.9	3636362.3	295	2.88	7.81	Y	105	154.4	39.76667	3
31900004	BASF Corporation,	Kaolin Glay	TV	Hwy 18 Spur, Macon	Wilkinson	1	#3 Spray Dryer	41.00	17	281101.3	3640453.4	357	6.44	n/a	Y	78	220	68.5	4.2
	Gordon Plant	Processing		Road, Gordon, GA		2	#2 Spray Dryer	41.03	17	281111.4	3640401.0	354	6.44	n/a	Y	78	220	68.5	4.2
				31031		3	#1 Spray Dryer	40.98	17	281052.6	3640577.6	357	4.25	n/a	Y	80	220	64	3.5
						4	Slip Heater #2	41.00	17	281057.0	3640525.3	358	1.14	n/a	Y	30	150	24.3	3.3
						5	Slip Heater #1	41.02	17	281040.9	3640516.8	359	1.14	n/a	Y	30	150	24.3	3.3
						6	Thermal #3	40.97	17	281022.7	3640624.9	357	1.86	n/a	Y	43	150	24.3	3.3
						7	Thermal #2	40.98	17	281032.6	3640606.9	357	1.86	n/a	Y	43	150	24.3	3.3
						8	#3 Calciner	40.90	17	281145.2	3640575.5	354	1.29	n/a	N	69	160	21.3	2.8
						9	#4 Calciner	40.90	17	281151.7	3640573.2	354	1.71	n/a	Y	69	160	21.3	2.8
						10	#5 Calciner	40.91	17	281140.3	3640566.8	355	1.71	n/a	Y	69	160	21.3	2.8
						11	#2 Calciner	40.83	17	281226.0	3640587.1	352	0.57	n/a	Y	58	150	43.9	1.3
						12	#6 Calciner	40.85	17	281225.9	3640541.6	353	1.71	n/a	Y	100	160	88.8	1.7
						13	#4 Spray Dryer	40.88	17	281419.6	3640197.8	337	8.29	n/a	Y	135	220	54	5.5

Table D-27. Regional Source Inventory Stack Parameters

AIRS	Name	Facility Description	Type	Address	County	Stack	Stack Description	Distance (km)	Zone	UTM E (m)	UTM N (m)	Elev (ft)	NO_X (lb/hr)	$PM_{2.5}$ (lb/hr)	Horizontal Stack? (Y/N)	Height (ft)	Temperature (F)	Velocity (ft/s)	Diameter (ft)
						14	#1 Calciner	40.82	17	281228.8	3640588.1	352	0.51	n/a	Y	58	150	43.9	1.3
00900031	Triumph Aerostructures, LLC - Vought Aircraft Division	Milledgeville	TV	90 Highway 22 West, Milledgeville, Georgia 31061	Baldwin	1	Gordon Paitt Boiler	28.60	17	286579	3663070		2.59	n/a	Vertical with rain cap	30.0	525	--	3
						2	TEC Autoclave	28.60	17	286579	3663070		1.20	n/a	Y	30.0	525	--	1
						3	ASC Autoclave	28.60	17	286579	3663070		1.92	n/a	Y	32.0	525	--	2
31900029	Carbo Ceramics Toomsboro Plant	Ceramic Pellet Manufacturing	TV	1880 Dent Road, Toomsboro, Georgia 31090	Wilkinson	1	Spray Dryer #1	30.20	17	301020	3636585		8.30	n/a	N	160	206	92.4	3.30
						2	Spray Dryer #2	30.21	17	301013	3636577		8.30	n/a	N	160	206	92.4	3.30
						3	Calciner/Kiln No. 1 & Cooler	30.24	17	300994	3636551		121.00	n/a	N	170	425	99.4	3.70
						4	Spray Dryer #3	30.19	17	301009	3636600		8.30	n/a	N	170	206	76.0	3.60
						5	Spray Dryer #4	30.21	17	301000	3636592		8.30	n/a	N	170	206	76.0	3.60
						6	Calciner/Kiln No. 2 & Cooler	30.23	17	300977	3636576		121.00	n/a	N	195	425	77.0	4.20
						7	Spray Dryer No. 5	30.15	17	300929	3636695		8.30	n/a	N	170	206	76.0	3.60
						8	Spray Dryer No. 6	30.16	17	300920	3636688		8.30	n/a	N	170	206	76.0	3.60
						9	Kiln No. 3	30.19	17	300898	3636662		121.00	n/a	N	195	425	77.0	4.20
						10	Spray Dryer No. 7	30.14	17	300916	3636710		8.30	n/a	N	170	206	76.0	3.60
						11	Spray Dryer No. 8	30.15	17	300909	3636702		8.30	n/a	N	170	206	76.0	3.60
						12	Kiln No. 4	30.18	17	300878	3636687		121.00	n/a	N	195	425	77.0	4.20
						13	Boiler 1	30.22	17	301020	3636562		0.14	n/a	N	29.0	380	0.10	1.50
						14	Boiler 2	30.23	17	300944	3636593		0.14	n/a	N	29.0	380	0.10	1.50
						15	Boiler 3	30.22	17	300900	3636634		0.14	n/a	N	29.0	380	0.10	1.50
						16	Boiler 4	30.20	17	300886	3636654		0.14	n/a	N	29.0	380	0.10	1.50
						17	Horizontal Stack for New Coating Dryer	30.20	17	300929	3636634		0.18	n/a	N	15.0	120	51.8	2.00
						18		30.76	17	299183	3636991		0.05	n/a	N	20.0	100	0.30	0.50
						19	Baghouse for Grit Dryer GRD1	30.20	17	300929	3636634		1.76	n/a	N	1.00	180	0.10	1.00
31900027	Carbo Ceramics McIntyre Plant	Ceramic Pellet Manufacturing	TV	2295 Wriley Road, McIntyre, Georgia 31054	Wilkinson	1	Cage Mill	32.06	17	297578	3636461		12.00	n/a	N	140	250	124	2.50
						2	Calciner No. 1	32.04	17	297617	3636464		5.00	n/a	N	180	400	109	1.20
						3	Dryer #1 (Rotary Dryer)	32.06	17	297551	3636483		5.32	n/a	N	180	225	114	2.50
						4	Dryer #2 (Rotary Dryer)	32.07	17	297551	3636475		5.32	n/a	N	180	225	114	2.50
						5	Kiln #1 (Rotary Calciner)	32.04	17	297610	3636468		82.00	n/a	N	190	400	119	2.50
						6	Kiln #2 (Rotary Calciner)	32.03	17	297610	3636480		82.00	n/a	N	190	400	119	2.50
						7	Pulverizer #1	32.02	17	297633	3636478		10.00	n/a	N	190	255	114	1.50
						8	Pulverizer #2	32.03	17	297633	3636468		10.00	n/a	N	190	255	114	1.50
						9	Calciner No. 2	32.11	17	297573	3636407		40.00	n/a	N	190	255	114	1.50
23700010	Interfor U.S. Eatonton Sawmill	Lumber Mill	TV	370 Dennis Station Road SW, Eatonton,	Putnam	1	Boiler	39.19	17	280068	3680687		16.40	n/a	N	58.0	160	53.4	3.50
						2	Continuous Kiln	39.04	17	280202	3680617		3.84	n/a	N	36.5	230	41.8	2.70
30100003	GP Wood Products (Warrenton)	Sawmill	TV	331 Thomson Highway, NE, Warrenton, Georgia 30828	Warren	1	Package NG Boiler	47.06	17	346925	3697998		1.37	n/a	N	26.7	300	21.7	2.50
						2	Continuous Kiln No. 4	47.06	17	346925	3697998		2.83	n/a	N	41.2	110	58.2	2.80
						3	Continuous Kiln No. 5	47.06	17	346925	3697998		2.83	n/a	N	41.2	110	71.5	2.80
						4	Continuous Kiln No. 6	47.06	17	346925	3697998		2.43	n/a	N	41.2	110	71.5	2.80

Table D-28. Regional Source Inventory Stack Parameters_SI Units

Stack ID	Description	Horizontal Stack? (Y/N)	X	Y	Elevation (m)	NOx Emission Rate (g/s)	$PM_{2.5}$ Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
CSH1	Central State Hospital Boiler Number 1	N	292729	3658696	95.79	1.57	n/a	13.72	449.82	21.95	0.91
CSH2	Central State Hospital Boiler Number 2	N	292721	3658692	96.39	1.57	n/a	13.72	449.82	21.95	0.91
CSH3	Central State Hospital Boiler Number 3	N	292715	3658668	94.01	2.37	n/a	15.24	449.82	15.24	0.91
CSH4	Central State Hospital Boiler Number 4	N	292708	3658665	94.25	2.37	n/a	15.24	449.82	15.24	0.91
CSH5	Central State Hospital Hospital Boiler Number 1	N	294297	3656452	119.73	0.30	n/a	13.72	449.82	6.10	0.76
CSH6	Central State Hospital Hospital Boiler Number 2	N	294210	3656499	125.08	0.30	n/a	13.72	449.82	6.10	0.76
SNG1	SNG Hall Gate Compressor Engine No. 1	N	308127	3660004	135.50	5.41	n/a	10.88	649.82	27.89	0.73
SNG2	SNG Hall Gate Compressor Engine No. 2	N	308136	3660008	135.41	5.41	n/a	10.88	649.82	27.89	0.73
SNG3	SNG Hall Gate Compressor Engine No. 3	N	308161	3660023	134.82	0.99	n/a	12.19	732.04	17.43	0.91
ISCP1	IMERYS Sandersville Calcine Plant Spray Dryer No. 3	N	329793	3649055	137.28	0.72	0.37	41.15	365.93	27.43	1.01
ISCP2	IMERYS Sandersville Calcine Plant Spray Dryer No. 4	N	329704	3649024	136.16	0.72	0.43	41.15	365.93	27.43	1.01
ISCP3	IMERYS Sandersville Calcine Plant Calciner No. 1	N	329612	3649054	136.42	0.36	0.13	42.67	344.26	11.40	0.61
ISCP4	IMERYS Sandersville Calcine Plant Calciner No. 2	N	329708	3649020	136.23	0.36	0.15	45.72	339.26	12.59	0.61
ISCP5	IMERYS Sandersville Calcine Plant Calciner No. 3	N	329708	3649048	135.78	0.36	0.15	45.72	339.26	12.59	0.61
ISCP6	IMERYS Sandersville Calcine Plant Calciner No. 4	N	329724	3649052	135.94	0.65	0.27	61.57	339.26	12.01	0.85
TKCSP1	Thiele Kaolin Company - Sandersville Plant Spray Dryer No. 1	N	329908	3649456	136.98	0.43	1.36	19.81	392.04	31.70	0.91
TKCSP2	Thiele Kaolin Company - Sandersville Plant Spray Dryer No. 2	N	329896	3649444	137.23	0.43	0.58	17.07	382.04	17.95	0.91
TKCSP3	Thiele Kaolin Company - Sandersville Plant Spray Dryer No. 3	N	329876	3649457	137.28	0.43	0.58	18.90	362.59	14.84	1.01
TKCSP4	Thiele Kaolin Company - Sandersville Plant Spray Dryer No. 4	N	329884	3649440	137.23	0.93	1.06	48.77	365.93	17.31	1.68
TKCSP5	Thiele Kaolin Company - Sandersville Plant Spray Dryer No. 5	N	329862	3649345	137.22	0.93	1.01	53.34	366.48	16.61	1.68
TKCSP6	Thiele Kaolin Company - Sandersville Plant Calciner No. 1/SD6	N	329882	3649349	137.36	0.68	0.14	53.34	324.82	8.63	1.52
TKCSP7	Thiele Kaolin Company - Sandersville Plant Calciner No. 2/SD7	N	329882	3649349	137.36	0.68	0.14	53.34	324.82	8.63	1.52
TKCSP8	Thiele Kaolin Company - Sandersville Plant New Boiler	N	329884	3649484	137.03	0.36	0.24	9.14	460.93	7.38	0.70
TKCSP9	Thiele Kaolin Company - Sandersville Plant Generator 1	N	329870	3649353	137.20	0.49	1.13E-02	6.10	747.04	128.63	0.21
TKCSP10	Thiele Kaolin Company - Sandersville Plant Generator 2	N	329862	3649341	137.27	0.49	1.13E-02	6.10	747.04	128.63	0.21
IDRP1	IMERYS Deepstep Road Plant Boiler No. 3	N	324435	3655740	129.32	0.54	7.43E-02	10.97	449.82	13.08	0.61
IDRP2	IMERYS Deepstep Road Plant Boiler No. 4	N	324439	3655724	129.20	0.54	7.43E-02	10.97	449.82	13.08	0.61
IDRP3	IMERYS Deepstep Road Plant Boiler No. 5	N	324463	3655736	129.06	0.63	8.57E-02	10.97	449.82	13.08	0.61
IDRP4	IMERYS Deepstep Road Plant Spray Dryer No. 1	N	324423	3655724	129.30	0.60	2.65	24.69	335.93	15.85	1.07
IDRP5	IMERYS Deepstep Road Plant Spray Dryer No. 2	N	324419	3655725	129.32	0.69	3.86	27.43	335.93	15.54	1.58
IDRP6	IMERYS Deepstep Road Plant Spray Dryer No. 3	N	324431	3655724	129.26	0.69	3.86	27.43	335.93	15.54	1.58
IDRP7	IMERYS Deepstep Road Plant Spray Dryer No. 4	N	324443	3655720	129.16	0.69	3.86	27.43	335.93	15.54	1.58
IDRP8	IMERYS Deepstep Road Plant Apron Dryer (South Stack)	N	324443	3655720	129.16	0.21	0.47	9.14	377.59	11.31	0.91
IDRP9	IMERYS Deepstep Road Plant Apron Dryer (North Stack 1)	N	324447	3655712	129.09	0.21	0.47	9.14	418.15	10.64	0.76
IDRP10	IMERYS Deepstep Road Plant Apron Dryer (North Stack 2)	N	324435	3655740	129.32	0.21	0.47	9.14	418.15	10.64	0.76
BPC1	Burgess Pigment Company No. 1B Calciner	N	329959	3649142	138.87	0.81	1.18	13.72	305.93	20.42	0.40
BPC2	Burgess Pigment Company No. 2 Calciner	N	329959	3649142	138.87	0.23	1.46	20.73	328.71	20.42	0.55
BPC3	Burgess Pigment Company No. 4 Calciner	N	329959	3649142	138.87	0.38	1.71	19.81	348.15	32.00	0.73
BPC4	Burgess Pigment Company No. 5 Calciner	N	329959	3649142	138.87	0.23	0.19	31.09	357.04	14.39	0.70
BPC5	Burgess Pigment Company No. 6 Calciner	N	329959	3649142	138.87	0.32	0.31	40.54	389.26	25.91	0.91
BPC6	Burgess Pigment Company No. 7 Calciner	N	329959	3649142	138.87	0.23	0.19	30.48	397.04	20.54	0.70
KM1	KaMin - Sandersville Boiler No. 1	N	329959	3649142	138.87	0.23	6.05E-02	7.62	422.04	11.58	0.52
KM2	KaMin - Sandersville Boiler No. 2	N	329959	3649142	138.87	0.23	6.05E-02	7.62	422.04	11.58	0.52
KM3	KaMin - Sandersville Boiler No. 3	N	329562	3649221	133.35	0.30	6.05E-02	9.14	422.04	11.58	0.52
KM4	KaMin - Sandersville Boiler No. 5	N	329959	3649142	138.87	0.60	3.02E-02	9.14	422.04	11.58	0.52
KM5	KaMin - Sandersville Spray Dryer No. 1	N	329601	3649549	134.40	0.72	0.50	25.91	338.71	10.91	1.22
KM6	KaMin - Sandersville Spray Dryer No. 2	N	329959	3649142	138.87	0.72	0.50	25.91	338.71	10.91	1.22
KM7	KaMin - Sandersville Spray Dryer No. 5	N	329494	3649264	130.80	1.44	0.59	25.91	338.71	11.77	1.22
KM8	KaMin - Sandersville Calciner No. 5	N	329458	3649241	132.27	0.64	0.30	36.58	355.37	13.01	0.82

Table D-28. Regional Source Inventory Stack Parameters_SI Units

Stack ID	Description	Horizontal Stack? (Y/N)	X	Y	Elevation (m)	NOx Emission Rate (g/s)	$PM_{2.5}$ Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
ALS1	AL Sandersville Combustion Turbine 1	N	326431	3665915	138.60	24.32	n/a	19.81	810.37	42.37	4.57
ALS2	AL Sandersville Combustion Turbine 2	N	326369	3665990	137.41	24.32	n/a	19.81	810.37	42.37	4.57
ALS3	AL Sandersville Combustion Turbine 3	N	326288	3666096	133.17	24.32	n/a	19.81	810.37	42.37	4.57
ALS4	AL Sandersville Combustion Turbine 4	N	326411	3665936	139.13	24.32	n/a	19.81	810.37	42.37	4.57
ALS5	AL Sandersville Combustion Turbine 5	N	326388	3665968	139.23	24.32	n/a	19.81	810.37	42.37	4.57
ALS6	AL Sandersville Combustion Turbine 6	N	326346	3666021	134.00	24.32	n/a	19.81	810.37	42.37	4.57
ALS7	AL Sandersville Combustion Turbine 7	N	326330	3666043	132.77	24.32	n/a	19.81	810.37	42.37	4.57
ALS8	AL Sandersville Combustion Turbine 8	N	326302	3666082	132.67	24.32	n/a	19.81	810.37	42.37	4.57
KTC511	Kent-Tenn Clay (Plt 51/52) Rotary Dryer, railcar loading (1)	N	330154.6	3649617.16	128.63	0.19	1.07	6.40	341.48	10.16	0.77
KTC512	Kent-Tenn Clay (Plt 51/52) Raymond Mill Nos 1 and 2	N	330154.6	3649617.16	128.63	0.11	1.51	16.76	341.48	10.00	0.92
KTC513	Kent-Tenn Clay (Plt 51/52) Bulk Bag Loader, Dual Feed Bin Loading (3)	N	330154.6	3649617.16	128.63	0.00E+00	2.15E-02	17.07	366.48	5.08	0.38
KTC531	Kent-Tenn Clay (Plt 53) Reject Silo No. 1	Y	324889.01	3654188.08	132.48	0.00E+00	2.67E-02	19.81	556.48	17.49	0.20
KTC532	Kent-Tenn Clay (Plt 53) Reject Silo No. 2	Y	324889.01	3654188.08	132.48	0.00E+00	2.14E-02	19.81	293.15	13.09	0.20
KTC533	Kent-Tenn Clay (Plt 53) Rotary Dryer	Y	324889.01	3654188.08	132.48	0.16	0.28	12.19	371.48	19.42	0.43
KTC534	Kent-Tenn Clay (Plt 53) No. 1 Raymond Mill with Dryer	N	324889.01	3654188.08	132.48	6.17E-02	0.28	10.36	358.15	35.41	0.53
KTC535	Kent-Tenn Clay (Plt 53) No. 1 Raymond Mill Fugitives	N	324889.01	3654188.08	132.48	0.00E+00	6.02E-02	10.97	307.59	11.31	0.38
KTC536	Kent-Tenn Clay (Plt 53) Cage Mill Dryer	N	324889.01	3654188.08	132.48	0.17	0.32	2.44	337.04	18.02	0.83
KTC537	Kent-Tenn Clay (Plt 53) No. 2 Raymond Mill Feed Bin	N	324889.01	3654188.08	132.48	0.00E+00	8.32E-03	12.19	295.37	20.78	0.10
KTC538	Kent-Tenn Clay (Plt 53) No. 2 Raymond Mill with Dryer	Y	324889.01	3654188.08	132.48	9.88E-02	0.31	13.72	347.59	29.57	0.63
KTC539	Kent-Tenn Clay (Plt 53) No. 2 Raymond Mill Rejects/Fugitives	N	324889.01	3654188.08	132.48	0.00E+00	0.11	11.58	305.37	32.34	0.30
KTC5310	Kent-Tenn Clay (Plt 53) Silos No. 4 and 5 Fugitives and Railcar Bulk Loadout No. 1	N	324889.01	3654188.08	132.48	0.00E+00	3.39E-02	10.06	305.93	7.36	0.36
KTC5311	Kent-Tenn Clay (Plt 53) Silo No. 4	N	324889.01	3654188.08	132.48	0.00E+00	4.25E-02	15.85	295.37	26.19	0.20
KTC5312	Kent-Tenn Clay (Plt 53) Silo No. 5	N	324889.01	3654188.08	132.48	0.00E+00	4.71E-02	15.85	295.37	29.11	0.20
KTC5313	Kent-Tenn Clay (Plt 53) Silo No. 6, 7, 8, 9, and 10 and Railcar Bulk Loadout No. 2	N	324889.01	3654188.08	132.48	0.00E+00	0.11	17.37	309.82	33.42	0.30
KTC5314	Kent-Tenn Clay (Plt 53) Silo No. 11	N	324889.01	3654188.08	132.48	0.00E+00	9.44E-02	26.82	295.37	43.24	0.20
KTC5315	Kent-Tenn Clay (Plt 53) Silo No. 12 and Silos No. 11 and 12 Truck Loadout	N	324889.01	3654188.08	132.48	0.00E+00	7.07E-02	26.82	295.37	43.66	0.20
KTC5316	Kent-Tenn Clay (Plt 53) Silo No. 13 and Silo No. 13 Truck Loadout	N	324889.01	3654188.08	132.48	0.00E+00	8.26E-02	26.82	295.37	43.66	0.20
KTC5317	Kent-Tenn Clay (Plt 53) Silo No. 15 and Silo No. 15 Railcar Loadout	N	324889.01	3654188.08	132.48	0.00E+00	0.11	26.82	295.37	33.84	0.29
KTC5318	Kent-Tenn Clay (Plt 53) 50 Pound Baggers Palletizer	N	324889.01	3654188.08	132.48	0.00E+00	6.75E-02	13.11	313.15	37.63	0.22
KTC5319	Kent-Tenn Clay (Plt 53) 50 Pound Baggers	N	324889.01	3654188.08	132.48	0.00E+00	3.88E-02	13.11	315.37	21.90	0.22
KTC5320	Kent-Tenn Clay (Plt 53) Bulk Baggers No. 1 and 2 and Low Residue Bagger	N	324889.01	3654188.08	132.48	0.00E+00	0.11	4.57	295.93	24.07	0.34
KTC5321	Kent-Tenn Clay (Plt 53) No. 3 Williams Mill with Dryer	N	324889.01	3654188.08	132.48	0.25	0.50	16.46	340.37	24.75	0.89
KTC5322	Kent-Tenn Clay (Plt 53) Bulk Bagger No. 5	N	324889.01	3654188.08	132.48	0.00E+00	1.51E-02	4.57	295.93	24.07	0.34
KTC5323	Kent-Tenn Clay (Plt 53) Bulk Bagger No. 6	N	324889.01	3654188.08	132.48	0.00E+00	1.51E-02	4.57	295.93	24.07	0.34
TBC1	Trojan Batter Company, LLC Casting and Pasting	N	328291	3653255	131.28	4.33E-02	n/a	9.14	299.82	20.76	1.42
TBC2	Trojan Batter Company, LLC Assembly (1 Melt Pot)	N	328408	3653122	132.41	4.33E-02	n/a	9.14	299.82	20.76	1.42
TBC3	Trojan Batter Company, LLC Curing Ovens C01-C03	N	328286	3653219	131.50	4.33E-02	n/a	13.72	355.37	0.001	103.63
TBC4	Trojan Batter Company, LLC Curing Ovens C04-C07	N	328295	3653212	131.62	4.33E-02	n/a	13.72	355.37	0.001	103.63
PCC1	Pittman Construction Company, LLC Dryer Drum Mixer	N	323704.77	3681184.93	163.79	1.39	n/a	7.09	394.26	26.46	0.94
ARS1	ARI Railcar Services, LLC Boiler	N	329715.16	3645021.66	139.35	0.10	n/a	5.49	1088.71	9.74	0.46
ARS2	ARI Railcar Services, LLC Flare	N	329715.16	3645021.66	139.35	6.62E-03	n/a	5.08	2268.15	0.03	0.28

Table D-28. Regional Source Inventory Stack Parameters_SI Units

Stack ID	Description	Horizontal Stack? (Y/N)	X	Y	Elevation (m)	NOx Emission Rate (g/s)	$PM_{2.5}$ Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
ARS3	ARI Railcar Services, LLC 3 NG Direct Fired Heaters	N	329715.16	3645021.66	139.35	0.14	n/a	9.65	310.93	2.70	1.70
RR1	Rath Refractories Dryer 1 & 2 (P016)	N	286289.34	3663629.56	109.15	1.27E-02	n/a	10.06	423.15	13.27	0.41
RR2	Rath Refractories Kiln 1 & 2 (P017)	N	286289.34	3663629.56	109.15	1.89	n/a	18.29	599.82	10.99	1.01
RR3	Rath Refractories Kiln 3 (P023) Main Stack	N	286289.34	3663629.56	109.15	2.27	n/a	13.72	523.15	4.39	1.01
JEBCO1	Jebco, Inc. Drying Oven 1	N	343741.94	3697528.36	147.08	7.48E-05	n/a	14.63	418.15	1.80	0.15
JEBCO2	Jebco, Inc. Drying Oven 2	N	343741.94	3697528.36	147.08	7.48E-05	n/a	14.94	418.15	1.80	0.15
JEBCO3	Jebco, Inc. Drying Oven 3	N	343741.94	3697528.36	147.08	7.48E-05	n/a	14.94	418.15	1.80	0.15
JEBCO4	Jebco, Inc. Drying Oven 4	N	343741.94	3697528.36	147.08	7.48E-05	n/a	14.63	418.15	1.80	0.15
JEBCO5	Jebco, Inc. Drying Oven 5	N	343741.94	3697528.36	147.08	7.48E-05	n/a	10.06	483.67	2.01	0.15
JEBCO6	Jebco, Inc. Drying Oven 6	N	343741.94	3697528.36	147.08	7.48E-05	n/a	10.36	483.67	2.01	0.15
BASFT1	BASF Corporation, Toddville Plant 2A Spray Dryer	Y	291375.8	3637138.8	87.05	0.55	n/a	22.86	372.04	30.79	0.97
BASFT2	BASF Corporation, Toddville Plant 8B Boiler	Y	290837.8	3637116.9	94.32	0.16	n/a	6.10	291.54	17.22	0.46
BASFT3	BASF Corporation, Toddville Plant Toddville Boiler	Y	291448.7	3637046.3	87.55	0.12	n/a	6.10	291.54	8.60	0.51
BASFT4	BASF Corporation, Toddville Plant 2B Spray Dryer	Y	291388.9	3637137.5	86.91	0.55	n/a	19.81	372.04	30.79	0.97
BASFT5	BASF Corporation, Toddville Plant 2C Spray Dryer	Y	291402.3	3637151.6	86.60	0.55	n/a	19.81	372.04	30.79	0.97
BASFT6	BASF Corporation, Toddville Plant 2D Spray Dryer	Y	291482.3	3637082.2	86.79	0.88	n/a	23.47	380.37	19.47	1.27
BASFT7	BASF Corporation, Toddville Plant 2F Spray Dryer	Y	291495.1	3636978.8	88.98	1.44	n/a	39.62	383.15	1591.36	1.52
BASFT8	BASF Corporation, Toddville Plant 8D Boiler	Y	290843.6	3637123.5	94.12	0.31	n/a	7.01	291.54	17.22	0.46
BASFT9	BASF Corporation, Toddville Plant 8C Boiler	Y	290831.2	3637116	94.44	0.31	n/a	5.79	291.54	17.22	0.46
BASFT10	BASF Corporation, Toddville Plant Sargent Dryer	N	291394.2	3637168.4	86.52	0.11	n/a	12.19	291.54	26.04	1.37
BASFE1	BASF Corporation, Edgar Plant 11A Calciner	Y	292853.6	3636326.9	91.99	0.54	1.03	45.72	350.15	16.20	0.61
BASFE2	BASF Corporation, Edgar Plant 11F Calciner	Y	292469.3	3636489.5	90.32	0.75	9.06E-02	60.96	343.15	19.26	0.76
BASFE3	BASF Corporation, Edgar Plant 11F Spray Dryer	Y	292475	3636496.7	90.24	0.85	0.56	60.35	394.26	56.19	0.61
BASFE4	BASF Corporation, Edgar Plant 11G Calciner	Y	292457.3	3636443.3	90.69	0.75	0.13	60.35	291.54	32.41	0.91
BASFE5	BASF Corporation, Edgar Plant 11G Spray Dryer	Y	292458.1	3636441.7	90.70	0.85	0.49	60.05	394.26	12.31	1.22
BASFE6	BASF Corporation, Edgar Plant 15A Calciner	N	292806.8	3636394.4	90.67	0.32	3.85E-02	30.48	355.15	5.97	0.91
BASFE7	BASF Corporation, Edgar Plant 15A Spray Dryer	N	292826.1	3636382.2	91.13	0.37	1.06	28.65	360.93	6.77	1.22
BASFE8	BASF Corporation, Edgar Plant 15B Calciner	Y	292789.8	3636380.5	91.30	0.57	0.19	36.58	344.15	34.19	0.76
BASFE9	BASF Corporation, Edgar Plant 15B Spray Dryer	Y	292742.9	3636373.6	91.29	0.41	1.21	22.86	394.26	19.54	1.22
BASFE10	BASF Corporation, Edgar Plant Fluid Bed Dryer	Y	292428.3	3636517.8	90.58	0.34	0.41	48.77	291.54	14.16	0.91
BASFE11	BASF Corporation, Edgar Plant 11B Calciner	Y	292800.2	3636295.4	93.29	0.54	1.20	22.86	347.15	11.97	22.86
BASFE12	BASF Corporation, Edgar Plant #5 Filter Dryer	Y	292871.5	3636243.5	92.32	0.53	1.64	36.58	291.54	35.71	0.81
BASFE13	BASF Corporation, Edgar Plant 11C Calciner	Y	292853.7	3636354.2	91.59	0.32	0.95	45.72	355.15	11.45	0.91
BASFE14	BASF Corporation, Edgar Plant 1B Spray Dryer	N	292903.5	3636237.1	91.55	1.01	2.24	25.91	380.37	8.40	1.68
BASFE15	BASF Corporation, Edgar Plant 11E Calciner	N	292775.6	3636297.3	93.65	0.36	8.05E-08	35.05	341.15	16.08	0.76
BASFE16	BASF Corporation, Edgar Plant 11D Calciner	Y	292909.9	3636362.3	89.96	0.36	0.98	32.00	341.15	12.12	0.91
BASFG1	BASF Corporation, Gordon Plant #3 Spray Dryer	Y	281101.3	3640453.4	108.87	0.81	n/a	23.77	377.59	20.88	1.28
BASFG2	BASF Corporation, Gordon Plant #2 Spray Dryer	Y	281111.4	3640401	107.91	0.81	n/a	23.77	377.59	20.88	1.28
BASFG3	BASF Corporation, Gordon Plant #1 Spray Dryer	Y	281052.6	3640577.6	108.85	0.54	n/a	24.38	377.59	19.51	1.07
BASFG4	BASF Corporation, Gordon Plant Slip Heater #2	Y	281057	3640525.3	109.09	0.14	n/a	9.14	338.71	7.41	1.01
BASFG5	BASF Corporation, Gordon Plant Slip Heater #1	Y	281040.9	3640516.8	109.29	0.14	n/a	9.14	338.71	7.41	1.01
BASFG6	BASF Corporation, Gordon Plant Thermal #3	Y	281022.7	3640624.9	108.84	0.23	n/a	13.11	338.71	7.41	1.01
BASFG7	BASF Corporation, Gordon Plant Thermal #2	Y	281032.6	3640606.9	108.86	0.23	n/a	13.11	338.71	7.41	1.01
BASFG8	BASF Corporation, Gordon Plant #3 Calciner	N	281145.2	3640575.5	108.02	0.16	n/a	21.03	344.26	6.49	0.85
BASFG9	BASF Corporation, Gordon Plant #4 Calciner	Y	281151.7	3640573.2	107.97	0.22	n/a	21.03	344.26	6.49	0.85
BASFG10	BASF Corporation, Gordon Plant #5 Calciner	Y	281140.3	3640566.8	108.11	0.22	n/a	21.03	344.26	6.49	0.85
BASFG11	BASF Corporation, Gordon Plant #2 Calciner	Y	281226	3640587.1	107.21	7.19E-02	n/a	17.68	338.71	13.38	0.40
BASFG12	BASF Corporation, Gordon Plant #6 Calciner	Y	281225.9	3640541.6	107.56	0.22	n/a	30.48	344.26	27.07	0.52
BASFG13	BASF Corporation, Gordon Plant #4 Spray Dryer	Y	281419.6	3640197.8	102.67	1.04	n/a	41.15	377.59	16.46	1.68

Table D-28. Regional Source Inventory Stack Parameters_SI Units

Stack ID	Description	Horizontal Stack? (Y/N)	X	Y	Elevation (m)	NOx Emission Rate (g/s)	$PM_{2.5}$ Emission Rate (g/s)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
BASFG14	BASF Corporation, Gordon Plant #1 Calciner	Y	281228.8	3640588.1	107.18	6.47E-02	n/a	17.68	338.71	13.38	0.40
TA1	Triumph Aerostructures, LLC - Vought Aircraft Division Gordon Paitt Boiler	Vertical with rain cap	286579	3663070	97.43	0.33	n/a	9.14	547.04	0.001	0.91
TA2	Triumph Aerostructures, LLC - Vought Aircraft Division TEC Autoclave	Y	286579	3663070	97.43	0.15	n/a	9.14	547.04	0.001	0.30
TA3	Triumph Aerostructures, LLC - Vought Aircraft Division ASC Autoclave	Y	286579	3663070	97.43	0.24	n/a	9.75	547.04	0.001	0.61
CCTP1	Carbo Ceramics Toomsboro Plant Spray Dryer #1	N	301020	3636585	91.56	1.05	n/a	48.77	369.82	28.16	1.01
CCTP2	Carbo Ceramics Toomsboro Plant Spray Dryer #2	N	301013	3636577	90.77	1.05	n/a	48.77	369.82	28.16	1.01
CCTP3	Carbo Ceramics Toomsboro Plant Calciner/Kiln No. 1 & Cooler	N	300994	3636551	88.04	15.25	n/a	51.82	491.48	30.30	1.13
CCTP4	Carbo Ceramics Toomsboro Plant Spray Dryer #3	N	301009	3636600	92.22	1.05	n/a	51.82	369.82	23.16	1.10
CCTP5	Carbo Ceramics Toomsboro Plant Spray Dryer #4	N	301000	3636592	91.23	1.05	n/a	51.82	369.82	23.16	1.10
CCTP6	Carbo Ceramics Toomsboro Plant Calciner/Kiln No. 2 & Cooler	N	300977	3636576	89.07	15.25	n/a	59.44	491.48	23.47	1.28
CCTP7	Carbo Ceramics Toomsboro Plant Spray Dryer No. 5	N	300929	3636695	92.63	1.05	n/a	51.82	369.82	23.16	1.10
CCTP8	Carbo Ceramics Toomsboro Plant Spray Dryer No. 6	N	300920	3636688	92.02	1.05	n/a	51.82	369.82	23.16	1.10
CCTP9	Carbo Ceramics Toomsboro Plant Kiln No. 3	N	300898	3636662	89.94	15.25	n/a	59.44	491.48	23.47	1.28
CCTP10	Carbo Ceramics Toomsboro Plant Spray Dryer No. 7	N	300916	3636710	92.29	1.05	n/a	51.82	369.82	23.16	1.10
CCTP11	Carbo Ceramics Toomsboro Plant Spray Dryer No. 8	N	300909	3636702	91.75	1.05	n/a	51.82	369.82	23.16	1.10
CCTP12	Carbo Ceramics Toomsboro Plant Kiln No. 4	N	300878	3636687	89.33	15.25	n/a	59.44	491.48	23.47	1.28
CCTP13	Carbo Ceramics Toomsboro Plant Boiler 1	N	301020	3636562	90.30	1.76E-02	n/a	8.84	466.48	0.03	0.46
CCTP14	Carbo Ceramics Toomsboro Plant Boiler 2	N	300944	3636593	89.09	1.76E-02	n/a	8.84	466.48	0.03	0.46
CCTP15	Carbo Ceramics Toomsboro Plant Boiler 3	N	300900	3636634	89.04	1.76E-02	n/a	8.84	466.48	0.03	0.46
CCTP16	Carbo Ceramics Toomsboro Plant Boiler 4	N	300886	3636654	88.82	1.76E-02	n/a	8.84	466.48	0.03	0.46
CCTP17	Carbo Ceramics Toomsboro Plant Horizontal Stack for New Coating Dryer	N	300929	3636634	90.92	2.27E-02	n/a	4.57	322.04	15.79	0.61
CCTP18	Carbo Ceramics Toomsboro Plant	N	299183	3636991	73.00	6.30E-03	n/a	6.10	310.93	0.09	0.15
CCTP19	Carbo Ceramics Toomsboro Plant Baghouse for Grit Dryer GRD1	N	300929	3636634	90.92	0.22	n/a	0.30	355.37	0.03	0.30
CCMP1	Carbo Ceramics McIntyre Plant Cage Mill	N	297578	3636461	81.83	1.51	n/a	42.67	394.26	37.80	0.76
CCMP2	Carbo Ceramics McIntyre Plant Calciner No. 1	N	297617	3636464	80.26	0.63	n/a	54.86	477.59	33.22	0.37
CCMP3	Carbo Ceramics McIntyre Plant Dryer #1 (Rotary Dryer)	N	297551	3636483	80.29	0.67	n/a	54.86	380.37	34.75	0.76
CCMP4	Carbo Ceramics McIntyre Plant Dryer #2 (Rotary Dryer)	N	297551	3636475	81.19	0.67	n/a	54.86	380.37	34.75	0.76
CCMP5	Carbo Ceramics McIntyre Plant Kiln #1 (Rotary Calciner)	N	297610	3636468	80.05	10.33	n/a	57.91	477.59	36.27	0.76
CCMP6	Carbo Ceramics McIntyre Plant Kiln #2 (Rotary Calciner)	N	297610	3636480	79.12	10.33	n/a	57.91	477.59	36.27	0.76
CCMP7	Carbo Ceramics McIntyre Plant Pulverizer #1	N	297633	3636478	78.89	1.26	n/a	57.91	397.04	34.75	0.46
CCMP8	Carbo Ceramics McIntyre Plant Pulverizer #2	N	297633	3636468	79.55	1.26	n/a	57.91	397.04	34.75	0.46
CCMP9	Carbo Ceramics McIntyre Plant Calciner No. 2	N	297573	3636407	86.11	5.04	n/a	57.91	397.04	34.75	0.46
IES1	Interfor U.S. Eatonton Sawmill Boiler	N	280068	3680687	157.32	2.07	n/a	17.68	344.26	16.28	1.07
IES2	Interfor U.S. Eatonton Sawmill Continuous Kiln	N	280202	3680617	162.01	0.48	n/a	11.13	383.15	12.74	0.82
GPWP1	GP Wood Products (Warrenton) Package NG Boiler	N	346925	3697998	170.80	0.17	n/a	8.14	422.04	6.61	0.76
GPWP2	GP Wood Products (Warrenton) Continuous Kiln No. 4	N	346925	3697998	170.80	0.36	n/a	12.56	316.48	17.74	0.85
GPWP3	GP Wood Products (Warrenton) Continuous Kiln No. 5	N	346925	3697998	170.80	0.36	n/a	12.56	316.48	21.79	0.85
GPWP4	GP Wood Products (Warrenton) Continuous Kiln No. 6	N	346925	3697998	170.80	0.31	n/a	12.56	316.48	21.79	0.85

Table D-29. Facility-Wide TAP MER Analysis

Pollutant	CAS No.	Combustion Turbine 1 (T1) (tpy)	Combustion Turbine 2 (T2) (tpy)	Combustion Turbine 3 (T3) (tpy)	Combustion Turbine 4 (T4) (tpy)	Fuel Heater No. 1 (H1) (tpy)	Fuel Heater No. 2 (H2) (tpy)	Diesel Fired Emergency Generator (tpy)	Emergency Fire Water Pump (tpy)	Distillate Tank (T-1) (tpy)	Total Potential Emissions (tpy)	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER? (Y/N)
1,3-Butadiene	106990	8.70E-03	8.70E-03	8.70E-03	8.70E-03	--	--	3.55E-05	7.53E-06	--	3.48E-02	69.68	7.30	Y
2-Methylnaphthalene	91576	--	--	--	--	1.04E-06	1.04E-06	--	--	--	2.08E-06	4.16E-03	--	--
3-Methylcholanthrene	56495	--	--	--	--	7.81E-08	7.81E-08	--	--	--	1.56E-07	3.12E-04	--	--
7,12-Dimethylbenz(a)anthracene	57976	--	--	--	--	6.94E-07	6.94E-07	--	--	--	1.39E-06	2.78E-03	--	--
Acenaphthene	83329	--	--	--	--	7.81E-08	7.81E-08	4.60E-06	9.74E-07	--	5.73E-06	1.15E-02	--	--
Acenaphthylene	208968	--	--	--	--	7.81E-08	7.81E-08	1.29E-06	2.73E-07	--	1.72E-06	3.44E-03	--	--
Acetaldehyde	75070	1.06E-01	1.06E-01	1.06E-01	1.06E-01	--	--	6.97E-04	1.48E-04	--	0.42	849.37	1.11E+03	N
Acrolein	107028	1.70E-02	1.70E-02	1.70E-02	1.70E-02	--	--	8.40E-05	1.78E-05	--	6.79E-02	135.83	4.87	Y
Anthracene	120127	--	--	--	--	1.04E-07	1.04E-07	1.70E-06	3.60E-07	--	2.27E-06	4.53E-03	--	--
Arsenic	7440382	5.20E-03	5.20E-03	5.20E-03	5.20E-03	8.67E-06	8.67E-06	--	--	--	2.08E-02	41.61	5.67E-02	Y
Benz(a)anthracene	56553	--	--	--	--	7.81E-08	7.81E-08	1.53E-06	3.23E-07	--	2.01E-06	4.01E-03	--	--
Benzene	71432	5.78E-02	5.78E-02	5.78E-02	5.78E-02	9.11E-05	9.11E-05	8.47E-04	1.80E-04	1.31E-03	0.23	467.24	31.63	Y
Benzo(a)pyrene	50328	--	--	--	--	5.20E-08	5.20E-08	1.71E-07	3.62E-08	--	3.11E-07	6.22E-04	--	--
Benzo(b)fluoranthene	205992	--	--	--	--	7.81E-08	7.81E-08	9.00E-08	1.91E-08	--	2.65E-07	5.30E-04	--	--
Benzo(g,h,i)perylene	191242	--	--	--	--	5.20E-08	5.20E-08	4.44E-07	9.41E-08	--	6.42E-07	1.28E-03	--	--
Benzo(k)fluoranthene	207089	--	--	--	--	7.81E-08	7.81E-08	1.41E-07	2.98E-08	--	3.27E-07	6.54E-04	--	--
Beryllium	7440417	1.46E-04	1.46E-04	1.46E-04	1.46E-04	5.20E-07	5.20E-07	--	--	--	5.87E-04	1.17	0.97	Y
Cadmium	7440439	2.27E-03	2.27E-03	2.27E-03	2.27E-03	4.77E-05	4.77E-05	--	--	--	9.17E-03	18.33	1.35	Y
Chromium	7440473	5.20E-03	5.20E-03	5.20E-03	5.20E-03	6.07E-05	6.07E-05	--	--	--	2.09E-02	41.82	58.40	N
Chrysene	218019	--	--	--	--	7.81E-08	7.81E-08	3.21E-07	6.80E-08	--	5.45E-07	1.09E-03	--	--
Cobalt	7440484	--	--	--	--	3.64E-06	3.64E-06	--	--	--	7.29E-06	1.46E-02	11.68	N
Dibenzo(a,h)anthracene	53703	--	--	--	--	5.20E-08	5.20E-08	5.30E-07	1.12E-07	--	7.46E-07	1.49E-03	--	--
Dichlorobenzene	25321226	--	--	--	--	5.20E-05	5.20E-05	--	--	--	1.04E-04	0.21	--	--
Ethylbenzene	100414	8.48E-02	8.48E-02	8.48E-02	8.48E-02	--	--	--	--	2.03E-03	0.34	682.21	2.43E+05	N
Fluoranthene	206440	--	--	--	--	1.30E-07	1.30E-07	6.91E-06	1.46E-06	--	8.64E-06	1.73E-02	--	--
Fluorene	86737	--	--	--	--	1.21E-07	1.21E-07	2.65E-05	5.62E-06	--	3.24E-05	6.48E-02	--	--
Formaldehyde	50000	2.01	2.01	2.01	2.01	3.25E-03	3.25E-03	1.07E-03	2.27E-04	--	8.06	1.61E+04	267.00	Y
Hexane	110543	--	--	--	--	7.81E-02	7.81E-02	--	--	2.62E-04	0.16	312.79	1.70E+05	N
Indeno(1,2,3-cd)pyrene	193395	--	--	--	--	7.81E-08	7.81E-08	3.41E-07	7.22E-08	--	5.69E-07	1.14E-03	--	--
Lead	7439921	6.62E-03	6.62E-03	6.62E-03	6.62E-03	2.17E-05	2.17E-05	--	--	--	2.65E-02	53.01	5.84	Y
Manganese	7439965	3.73E-01	3.73E-01	3.73E-01	3.73E-01	1.65E-05	1.65E-05	--	--	--	1.49	2.99E+03	12.17	Y
Mercury	7439976	5.67E-04	5.67E-04	5.67E-04	5.67E-04	1.13E-05	1.13E-05	--	--	--	2.29E-03	4.58	73.00	N
Naphthalene	91203	2.00E-02	2.00E-02	2.00E-02	2.00E-02	2.65E-05	2.65E-05	7.70E-05	1.63E-05	3.10E-04	8.04E-02	160.76	729.99	N
Nickel	7440020	2.17E-03	2.17E-03	2.17E-03	2.17E-03	9.11E-05	9.11E-05	--	--	--	8.88E-03	17.75	38.64	N
Pentane	109660	--	--	--	--	1.13E-01	1.13E-01	--	--	--	0.23	451.05	3.42E+05	N
Propane	74986	--	--	--	--	6.94E-02	6.94E-02	--	--	--	0.14	277.57	2.09E+05	N
Phenanthrene	85018	--	--	--	--	7.37E-07	7.37E-07	2.67E-05	5.66E-06	--	3.38E-05	6.77E-02	--	--
Pyrene	129000	--	--	--	--	2.17E-07	2.17E-07	4.34E-06	9.20E-07	--	5.70E-06	1.14E-02	--	--
Propylene oxide	75569	7.68E-02	7.68E-02	7.68E-02	7.68E-02	--	--	--	--	--	0.31	614.57	656.99	N
Selenium	7782492	1.18E-02	1.18E-02	1.18E-02	1.18E-02	1.04E-06	1.04E-06	--	--	--	4.73E-02	94.50	23.36	Y
Toluene	108883	3.44E-01	3.44E-01	3.44E-01	3.44E-01	1.47E-04	1.47E-04	3.71E-04	7.87E-05	1.53E-02	1.39	2.79E+03	1.22E+06	N
Xylene	1330207	--	--	--	--	--	--	--	--	3.96E-02	3.96E-02	79.29	2.43E+04	N
Sulfuric Acid	7664939	1.25E+00	1.25E+00	1.25E+00	1.25E+00	1.42E-02	1.42E-02	--	--	--	5.02	1.00E+04	116.81	Y

Table D-30. TAP Modeling Emission Inputs (lb/hr)[1]

Stack	1,3-Butadiene 106990	Acrolein 107028	Arsenic 7440382	Benzene 71432	Beryllium 7440417	Cadmium 7440439	Formaldehyde 50000	Lead 7439921	Manganese 7439965	Selenium 7782492	Sulfuric Acid 7664939
T1	3.02E-02	1.13E-02	2.08E-02	1.04E-01	5.86E-04	9.07E-03	1.25E+00	2.65E-02	1.49E+00	4.73E-02	0.76
T2	3.02E-02	1.13E-02	2.08E-02	1.04E-01	5.86E-04	9.07E-03	1.25E+00	2.65E-02	1.49E+00	4.73E-02	0.76
T3	3.02E-02	1.13E-02	2.08E-02	1.04E-01	5.86E-04	9.07E-03	1.25E+00	2.65E-02	1.49E+00	4.73E-02	0.76
T4	3.02E-02	1.13E-02	2.08E-02	1.04E-01	5.86E-04	9.07E-03	1.25E+00	2.65E-02	1.49E+00	4.73E-02	0.76
H1	--	--	1.98E-06	2.08E-05	1.19E-07	1.09E-05	7.43E-04	4.95E-06	3.76E-06	2.38E-07	3.25E-03
H2	--	--	1.98E-06	2.08E-05	1.19E-07	1.09E-05	7.43E-04	4.95E-06	3.76E-06	2.38E-07	3.25E-03
TANK	--	--	--	2.99E-04	--	--	--	--	--	--	--

1. For combustion turbines, emissions are based on max short-term emission rates from natural gas or fuel oil combustion.

Table D-31. TAP Modeling Emission Inputs (g/s)[1]

Stack	1,3-Butadiene 106990	Acrolein 107028	Arsenic 7440382	Benzene 71432	Beryllium 7440417	Cadmium 7440439	Formaldehyde 50000	Lead 7439921	Manganese 7439965	Selenium 7782492	Sulfuric Acid 7664939
T1	3.81E-03	1.42E-03	2.62E-03	1.31E-02	7.38E-05	1.14E-03	1.58E-01	3.33E-03	1.88E-01	5.95E-03	9.53E-02
T2	3.81E-03	1.42E-03	2.62E-03	1.31E-02	7.38E-05	1.14E-03	1.58E-01	3.33E-03	1.88E-01	5.95E-03	9.53E-02
T3	3.81E-03	1.42E-03	2.62E-03	1.31E-02	7.38E-05	1.14E-03	1.58E-01	3.33E-03	1.88E-01	5.95E-03	9.53E-02
T4	3.81E-03	1.42E-03	2.62E-03	1.31E-02	7.38E-05	1.14E-03	1.58E-01	3.33E-03	1.88E-01	5.95E-03	9.53E-02
H1	--	--	2.50E-07	2.62E-06	1.50E-08	1.37E-06	9.36E-05	6.24E-07	4.74E-07	2.99E-08	4.09E-04
H2	--	--	2.50E-07	2.62E-06	1.50E-08	1.37E-06	9.36E-05	6.24E-07	4.74E-07	2.99E-08	4.09E-04
TANK	--	--	--	3.76E-05	--	--	--	--	--	--	--

1. For combustion turbines, emissions are based on max short-term emission rates from natural gas or fuel oil combustion.

APPENDIX E. ELECTRONIC MODELING FILES