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

PSD PERMIT APPLICATION

Volume I – Construction Permit Application

Fuel Oil Conversion Project

Oglethorpe Power Corporation – Talbot Energy Facility

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1. EXECUTIVE SUMMARY

Oglethorpe Power Corporation ("OPC") owns and operates the Talbot Energy Facility, a simple-cycle power generation facility in Box Springs, Talbot County, Georgia (the "Facility"). The Facility consists of six Siemens-Westinghouse simple-cycle combustion turbines, with the capacity to generate approximately 108 MW of power each, along with other ancillary equipment including three natural gas-fired fuel gas heaters. Four of the existing combustion turbines (Source Codes: T1 - T4) fire solely natural gas, while the remaining two (Source Codes: T5 and T6) primarily fire natural gas with distillate fuel oil as a back-up fuel. The Facility currently operates under Permit No. 4911-263-0013-V-07-0, issued February 1, 2021, by the Georgia Environmental Protection Division (EPD).

The Facility is proposing to modify the four existing natural gas-fired turbines (Source Codes: T1 - T4) to allow for the use of distillate fuel oil as a back-up fuel. OPC is proposing for each combustion turbine to operate for a maximum of 4,200 hours per 12-month rolling period on any fuel, of which up to 450 hours per 12-month rolling period can be on fuel oil. To accommodate this request, the Facility is also proposing to install two new fuel oil storage tanks and a new emergency diesel-fired fire pump engine to provide water for fire suppression in the event power is unavailable for the primary electric pump, assuming up to 500 hours of potential operation per 12-month rolling period on diesel (fuel oil) for the fire pump engine.

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

This 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 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. The proposed project represents 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. 767450.

1.1 Proposed Project Description

OPC is proposing the addition of fuel oil combustion capability for four of the Facility's six existing combustion turbines to enhance system reliability and to provide support and meet demand during times of natural gas supply curtailment and interruption. This project requires physical modifications to each of the four turbines to add fuel oil burners, installation of fuel oil storage capacity, and the addition of an emergency diesel-fired fire pump engine. OPC is requesting permit conditions limiting the total annual hours of operation for each modified combustion turbine to no more than 4,200 hours per 12-month rolling period, and limiting fuel oil firing to no more than 450 hours per 12-month rolling period per unit. OPC is also requesting a permit condition limiting annual operation for the emergency fire pump engine to no more than 500 hours per 12-month rolling period. More detail regarding the proposed project is provided in Section 2 of this application.

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

1.2 Permitting and Regulatory Requirements

OPC is submitting this construction and operating permit application, in accordance with the PSD permitting requirements, to request authorization to modify four of the Facility's six existing simple-cycle combustion turbines and operate them as modified. Since the Facility is a major source under the PSD permitting program, emission increases from the proposed project must be evaluated and compared to the SER thresholds for regulated pollutants under the PSD program. OPC has evaluated emissions increases of CO, NO_X, filterable PM, total PM_{10}, total $PM_{2.5}$, CO_2e, sulfur dioxide (SO_2), lead (Pb), 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.

Table 1-1. Proposed Project Emissions Increases

Pollutant	Project Emissions Increases (tpy)	PSD Significant Emission Rate (tpy)	PSD Triggered? (Yes/No)
Filterable PM	32.73	25	Yes
Total PM_{10}	107.81	15	Yes
Total $PM_{2.5}$	107.81	10	Yes
SO_2	5.90	40	No
NO_X	554.16	40	Yes
VOC	44.97	40	Yes
CO	314.18	100	Yes
CO_2e	954,964	75,000	Yes
Lead	1.7E-02	0.60	No
Sulfuric Acid Mist	0.59	7.00	No

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

OPC is submitting this construction and operating permit application package in accordance with all federal and state requirements. The proposed project will be subject to applicable 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

OPC 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 energy, environmental, and/or economic impacts indicate that the most stringent control option does not meet the definition of BACT. Where the top control option is not determined to be BACT, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected. Based on the BACT review, OPC proposes the technology and limits presented in Table 1-2 as BACT for each modified and new emission unit. 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
Simple Cycle Combustion Turbines (T1 -T4)	NO_X	Natural Gas	DLN Combustors and Good Combustion and Operating Practices	12.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	CEMS
		Fuel Oil	Water Injection and Good Combustion and Operating Practices	42.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	156.8 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	0.0137 lb/MMBtu - Equivalent to 16.2 lb/hr	Performance Test
		Fuel Oil		0.017 lb/MMBtu - Equivalent to 23.2 lb/hr	
	CO	Natural Gas	Good Combustion and Operating Practices	8.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	CEMS
		Fuel Oil		15.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	97.1 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	N/A	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	313,253 tpy CO_2e per rolling 12-months (each CCCT)	Records of Fuel Usage
Each Fuel Oil Storage Tank	VOC	N/A	Good Operating and Maintenance Practices, Submerged Fill Pipe, Paint Colors with Low Solar Absorptance		N/A
Emergency Fire Pump	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	4.0 g/kW-hr (3.0 lb/hp-hr)	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	ULSD		0.54 g/kW-hr (0.40 lb/hp-hr)	
	CO	ULSD		11.4 g/kW-hr (8.5 lb/hp-hr)	
	GHGs	ULSD		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;
- ► Appendix B includes the New Source Review (NSR) evaluation;
- ► Appendix C includes the detailed potential emissions calculations;
- ► Appendix D includes the control costs analyses completed in support of the BACT review;
- ► Appendix E includes the applicable Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database tables; and
- ► Appendix F contains the Georgia EPD SIP construction permit application forms.

2. PROPOSED PROJECT DESCRIPTION

OPC is proposing the addition of fuel oil combustion capability for four of the Facility's existing six combustion turbines to enhance system reliability and to provide support and meet demand during times of natural gas supply curtailment and interruption. This project requires physical modifications to each of the four turbines, installation of fuel oil storage capacity, and the addition of an emergency diesel-fired fire pump engine. OPC is requesting permit conditions limiting the total annual hours of operation from each modified turbine to no more than 4,200 hours per 12-month rolling period, and limiting fuel oil firing to no more than 450 hours per 12-month rolling period per unit. OPC proposes to operate Dry Low NO_X burners on the turbines during periods of natural gas combustion and proposes to install and operate a water-injection system to minimize the formation of NO_X emissions during periods of fuel oil combustion. The proposed new fuel oil storage capacity on-site is two 1.58 million gallon vertical fixed-roof storage tanks. OPC is also proposing to add a fire pump engine and associated fire water tank for use in case of an emergency. There are no other emission units at the Facility that OPC anticipates needing to add or modify as part of the proposed project.

The Talbot Energy Facility is a simple-cycle combustion turbine plant primarily used for peaking service and does not have a firm gas supply year-round. As a result, the primary natural gas fuel supply can be curtailed in periods of high demand or system disruptions. The ability to continue generating power in inclement weather events, or other interruptions when the natural gas supply is curtailed, is crucial for OPC's goal of providing reliable electrical power to its members.

As the Facility's turbines are large-frame simple-cycle units, startup and shutdown operations will generally be limited to less than 30 minutes for both gas and fuel oil operations. During gas combustion at 100% operating load, the heat input capacity is estimated to be 1,180 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 1,365 MMBtu/hr for each turbine.

OPC is proposing to begin construction of this project in the first quarter of 2024. Therefore, OPC is submitting this application into EPD's Expedited Permitting Program to ensure that a final permit is obtained by February 2024.

3. EMISSIONS CALCULATION METHODOLOGY

This section addresses the methodology used to quantify the emissions from the proposed project and assesses federal NSR permitting applicability. Emissions from the proposed project will include CO, NO_X, SO_2, VOC, PM, PM_{10}, $PM_{2.5}$, Pb, H_2SO_4, GHG in the form of CO_2e, and hazardous air pollutants (HAPs). These emissions occur as a result of natural gas and fuel oil combustion in the four modified combustion turbines and diesel fuel combustion in the proposed new emergency fire pump engine. Two new fuel oil storage tanks will also emit small quantities of VOC/HAPs. Detailed emission calculations are presented in Appendix C.

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 (PTE) 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 Talbot Energy Facility is located in Talbot County, which is presently designated as "attainment" or "unclassifiable" for all criteria pollutants.[2] As such, PSD permitting is potentially applicable to the proposed project.

The existing Facility is a PSD major source. Accordingly, if the proposed project meets the definition of *major modification,* 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.[3]

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 sources affected by the proposed project 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:

> (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.*

[2] 40 CFR 81.311

[3] 40 CFR 52.21(b)(49)(iii) as incorporated by reference in the GRAQC.

(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 OPC have operated for more than two years, the proposed project involves physical or operational changes to these existing emission units. The proposed fire pump engine and new fuel oil storage tanks will be considered new emission units.

3.3 Annual Emission Increase Calculation Methodology

As OPC is classified as a major source for PSD, if the proposed project meets 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 project does 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*[4] *<u>or</u> actual-to-potential; for new units, calculated by actual-to-potential]*[5]
>
> *(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 as the 5-year netting analysis. The netting analysis includes all projects for which emission increases or decreases (e.g., equipment shutdown) occurred. Only iff the resulting net emission increases also exceed

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[4] 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 emission</u>s … equals or exceeds the significant amount for that pollutant …*

[5] 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 …*

the major modification threshold, is PSD permitting required. OPC has evaluated the project emissions increase for the proposed project (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.

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", meaning that the use of a 10-year baseline period for actual emissions is appropriate.

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 project 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 project.

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 OPC can exclude emissions that could have been accommodated prior to the project and that are unrelated to the project, 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")...*
> [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 and (2) the increases do not result from the particular project (including, for example, emission increases related to increased product demand). As the proposed project entails the use of a new fuel, potential increases in emissions from the combustion of fuel oil would result from the proposed project; therefore, such 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. OPC does not expect any associated emissions increases from any emission units 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 applicable lookback period for baseline actual emissions is 10 years. For the purposes of selecting appropriate baseline actual emissions, OPC has obtained historically monitored monthly emission totals of NO_X, SO_2, CO, and CO_2 as well as historically monitored monthly heat inputs for each simple-cycle combustion turbine during the period of March 2014 through December 2022. 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 May 2015 to April 2017 was selected as the 2-year (consecutive 24-month) baseline period for PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, VOC, CO_2e, and H_2SO_4. Additionally, a period of January 2018 to December 2019 was selected as the 2-year (consecutive 24-month) baseline period for CO. Baseline actual emissions data utilized for the NSR analysis for each simple-cycle combustion turbine can be found in Appendix B.

3.4.2 Modified Units Potential-to-Emit

Project potential emissions for the four modified simple-cycle combustion turbines were determined for use in the NSR analysis and are based on up to 3,750 hours per year of natural gas-firing per unit and up to 450 hours per year of fuel oil-firing per unit. 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 emission estimates for NO_X, CO, and VOC considering and inclusive of startup/shutdown activities at the Facility. Under the Facility's operating permit, each combustion turbine is allowed up to 254 startup/shutdown cycles annually. This maximum number of annual events was then allocated to an estimated number of startup/shutdown cycles for both natural gas and fuel oil usage. These estimates of the number of startup/shutdown events were used along with estimates of emissions for the pollutants in question during a startup/shutdown hour, as provided by the turbine manufacturer, to estimate annual emissions.[6] Table 3-1 summarizes the emission factors utilized for estimation of emissions from natural gas combustion for the four modified simple-cycle combustion turbine units. Emission factor references are provided in Appendix B.

[6] Factors for each startup/shutdown event represent total emissions for an hour in which a startup or shutdown occurs.

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	12	ppmv at 15% O_2	Proposed BACT Limit
CO	8	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	EPA Emission Factor for Pipeline Natural Gas
H_2SO_4	0.00006	lb/MMBtu	Assumes 10% of SO_2 is converted to H_2SO_4

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	15	ppmv at 15% O_2	Proposed BACT Limit
VOC	5	ppmv at 15% O_2	Proposed BACT Limit
Total PM/PM_{10}/$PM_{2.5}$	0.017	lb/MMBtu	Equivalent to BACT Limit
SO_2	0.00151	lb/MMBtu	Emission Factor
Lead	0.000014	lb/MMBtu	EPA Emission Factor
H_2SO_4	0.000151	lb/MMBtu	Assumes 10% of SO_2 is converted to H_2SO_4

Additionally, GHG emissions from the combustion of natural gas and fuel oil are calculated based on the emission factors for CO_2 in Appendix G to 40 CFR 75 and emission factors for CH_4 and N_2O listed in 40 CFR 98 Subpart C, Table 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 A-1 to 40 CFR 98 Subpart A.

3.4.3 New Units Potential Emissions

A new emergency fire pump engine and two new fuel oil storage tanks are being proposed for installation. The fire pump engine is diesel-fired with a heat input capacity of 3.23 MMBtu/hr and is assumed to operate up to 500 hours per year. Each fuel oil storage tank will have a capacity of 1.58 million gallons and is assumed to operate continuously at 8,760 hours per year. Potential emissions from the storage tanks are estimated using the methodologies from Chapter 7 of AP-42 for VOC emissions from storage tanks. Physical data for the planned fuel oil storage tanks and area-specific meteorological data was utilized in the to generate an estimate of VOC emissions. For the purposes of estimating potential emissions, it is conservatively assumed that the tanks will experience a throughput equivalent to the potential fuel oil use of the modified turbines for a total fuel oil throughput of 8.775 million gallons per year per new tank.[7]

3.4.4 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	A Modified Unit Baseline Emissions (tpy)[1]	B Modified Unit Projected Actual Emissions (tpy)	C New Unit Potential Emissions (tpy)	D Emissions Increase from New & Modified Units (D = C + B - A) (tpy)	E Associated Units Emissions Increases (tpy)	F Project Emissions Increases (F = D + E) (tpy)	PSD Significant Emission Rate (tpy)	PSD Triggered? (Yes/No)
Filterable PM	9.96	42.68	0.01	32.73	--	32.73	25	Yes
Total PM_{10}	34.33	142.13	0.02	107.81	--	107.81	15	Yes
Total $PM_{2.5}$	34.33	142.13	0.02	107.81	--	107.81	10	Yes
SO_2	1.50	7.17	0.23	5.90	--	5.90	40	No
NO_X	73.90	627.29	0.77	554.16	--	554.16	40	Yes
VOC	6.37	50.36	0.97	44.97	--	44.97	40	Yes
CO	74.60	388.32	0.46	314.18	--	314.18	100	Yes
CO_2e	298,178	1,253,010	132.28	954,964	--	954,964	75,000	Yes
Lead	--	1.7E-02	--	1.7E-02	--	1.7E-02	0.60	No
Sulfuric Acid Mist	0.15	0.72	0.02	0.59	--	0.59	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 modified combustion turbine and the new fire pump engine and 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 Combustion Turbines Nos. 5 and 6

Potential emissions for the two existing, simple-cycle combustion turbines that are not subject to modification under this application were determined based on historical site potential emission calculations and Siemens-provided emissions data. Each unit is permitted to operate up to 4,200 hours annually on either fuel, of which up to 450 hours per year can be on fuel oil. As such, for the purposes of the potential emissions calculations, annual operations were based on 3,750 hours per year of natural gas firing and 450 hours per year of fuel oil firing. The potential emissions for each of these simple-cycle combustion turbines were determined on a pollutant-by-pollutant basis for the combustion of natural gas and fuel oil. See Appendix C for detailed calculations.

3.5.2 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 NO_X and CO are calculated based on limits in Permit Conditions 3.3.12 and 3.3.13, respectively. Emissions of Total PM/PM_{10}/$PM_{2.5}$, SO_2, VOC, and lead are

[7] Potential Turbine Fuel Oil Usage (MM gal/yr, each tank) = 1,365 (MMBtu/hr/turbine) / 0.140 (MMBtu/gal distillate oil) * 450 (hr/yr) / 10^6 (gal/MM gal) * 4 (turbines) / 2 (tanks) = 8.775 (MM gal/yr, each tank)

calculated using emission factors from AP-42 Section 1.4, *Natural Gas Combustion*, Tables 1.4-1 and 2 (July 1998). Sulfuric Acid (H_2SO_4) Mist is conservatively assumed as a portion (10%) of the SO_2 emissions. 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 A-1 to 40 CFR 98 Subpart A. See Appendix C for detailed calculations.

3.5.3 Emergency Fire Pump Engine

Emissions of criteria pollutants from the fire pump engine are calculated using emissions data from the manufacturer (Caterpillar) and AP-42 Section 3.3, *Gasoline and Diesel Industrial Engines*, Table 3.3-1 (October 1996). GHG emissions 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 A-1 to 40 CFR 98 Subpart A. Emissions from this engine is calculated assuming a maximum of 500 hours per year of operation. See Appendix C for detailed calculations.

3.5.4 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 C.

3.5.5 Insignificant Emissions Sources

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

4. REGULATORY APPLICABILITY ANALYSIS

The proposed project 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 the Facility as a result of this project. Potential applicability of NSR, Title V, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), GRAQC, and other potentially applicable regulations to the proposed project is 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 increase in emissions 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 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 "attainment" or "unclassifiable." The Talbot Energy Facility is located in Talbot County, which has been designated by the U.S. EPA as "attainment" or "unclassifiable" for all criteria pollutants.[8] Therefore, the proposed project is not potentially 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 tons per year (tpy) for all regulated pollutants, except GHG.[9, 10] The proposed project will require a PSD construction permit as a major modification to an existing major source. Projected-related emissions increases exceed the PSD SER thresholds for filterable PM, total PM_{10}, total $PM_{2.5}$, NO_X, VOC, CO, and CO_2e (although CO_2e does not alone trigger PSD permitting).

Since the Facility is a PSD major source for at least one regulated pollutant, the emissions increase 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 increase from the proposed project for each PSD-regulated pollutant compared to the respective SER are shown in Table 4-1.

[8] 40 CFR 81.311

[9] 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.

[10] 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 (tpy)	PSD Triggered? (Yes/No)
Filterable PM	32.73	25	Yes
Total PM_{10}	107.81	15	Yes
Total $PM_{2.5}$	107.81	10	Yes
SO_2	5.90	40	No
NO_X	554.16	40	Yes
VOC	44.97	40	Yes
CO	314.18	100	Yes
CO_2e	954,964	75,000	Yes
Lead	1.7E-02	0.60	No
Sulfuric Acid Mist	0.59	7.00	No

As illustrated in Table 4-1, the proposed project emissions increase (and net emission increase) 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 is defined under the Title V program as 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 HAPs. Potential emissions from the Talbot Energy Facility exceed the major source threshold for several criteria pollutants. Therefore, the Facility is subject to the Title V program and currently operates under the State issued Part 70 Operating Permit No. 4911-263-0013-V-07-0 issued February 1, 2021.

The proposed project represents 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. 767450.

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:[11]

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

The simple-cycle 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.[12] Following the proposed modifications, the four modified simple-cycle combustion turbines will be NSPS Subpart KKKK affected facilities.

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.[13] The rule defines an electric utility steam generating unit as:[14]

> …*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:[15]

> *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*

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[11] 40 CFR 60.41

[12] 40 CFR 60.40(e)

[13] 40 CFR 60.40Da(a)

[14] 40 CFR 60.41Da

[15] 40 CFR 60.41Da

steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; 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 the 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.[16] The term "steam generating unit" is defined under this regulation as:[17]

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.[18] 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 as simple-cycle combustion turbines are not steam generating units,[19] and each of the Facility's turbines has a heat input capacity greater than 100 MMBtu/hr.

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

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[16] 40 CFR 60.40b(a)

[17] 40 CFR 60.41b

[18] 40 CFR 60.40c(a)

[19] 40 CFR 60.41c

June 11, 1973 and prior to May 19, 1978.[20] The proposed fuel oil storage tanks at the Facility have 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.[21] The proposed fuel oil storage tanks at the Facility have 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.[22] However, per 40 CFR 60.110b(b), NSPS Subpart 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 tanks at the Facility will each have a storage capacity of 1.58 million gallons and will store ultra-low sulfur diesel (ULSD). The maximum true vapor pressure of the ULSD stored in the new fuel oil storage tanks 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.[23]

Presently, all six of the Facility's combustion turbines are subject to NSPS Subpart GG. However, upon completion of the proposed modification, the four modified combustion turbines T1 – T4 will become 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 combustion turbines T1 - T4 following the proposed project. Combustion turbines T5 and T6 are not being modified as part of the proposed project and will continue to be subject to the requirements of NSPS Subpart GG.

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[20] 40 CFR 60.110(c)

[21] 40 CFR 60.110a

[22] 40 CFR 60.110b(a)

[23] 40 CFR 60.330(a), (b)

4.3.10 40 CFR 60 Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, is potentially applicable to stationary internal combustion engines (ICE) based on the date each engine was constructed, reconstructed, or modified. The rule provides performance standards for both engine manufacturers and operators. Engine operators must meet the specified emission standards and fuel type specifications.

The Facility plans to construct and operate one new diesel-fired emergency fire pump (FP1). As FP1 will be manufactured after April 1, 2006, the unit will be subject to the requirements under this part.

FP1 will be rated at 455 hp. Pursuant to CFR 60.4202(d), FP1 must be certified to meet the applicable emission standards of Table 4 of NSPS Subpart IIII. Specifically, FP1 will be subject to the applicable emission limits for fire pump engines with a maximum engine power greater than 300 hp and less than 600 hp, and manufactured after 2009.

The engine will be certified by the engine to the applicable emission standards. In addition, the Facility will operate and maintain the engine according to the manufacturer's required schedules, including parts replacements, and the engine will be equipped with a non-resettable hour meter per the requirements of 40 CFR 60.4209(a).

4.3.11 40 CFR 60 Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ, *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*, is potentially applicable to stationary ICE based on the date each engine was constructed, reconstructed, or modified. The rule sets emissions standards for NO_X, CO, and VOC emissions for engines classified by size and date of manufacture or reconstruction. The proposed fire pump is diesel-fired, which is not spark ignition, and will not be subject to the requirements for NSPS Subpart JJJJ.

4.3.12 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, 2005.[24] The Facility presently operates six simple-cycle combustion turbines, each with a heat input capacity exceeding 10 MMBtu/hr. The proposed project involves physical modifications to four natural gas-fired combustion turbines, units T1 – T4, to add the capability of combusting fuel oil as a back-up fuel.[25] To determine if turbines T1 - T4 will become 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:[26]

> *…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*

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[24] 40 CFR 60.4305(a), (b)

[25] Combustion Turbine Nos. T5 and T6 are not being modified as a part of this project.

[26] 40 CFR 60.2

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.[27] As the combustion of fuel oil will result in increases in short-term emissions for both pollutants when compared to natural gas combustion, the proposed project qualifies as an NSPS modification, resulting in the four modified combustion turbines becoming 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 to turbines T1 - T4. Combustion turbines T5 and T6 will not be modified as part of the proposed project and will remain subject to the requirements of NSPS Subpart GG.

The following sections detail the applicable requirements as a result of NSPS Subpart KKKK applicability for turbines T1 - T4.

4.3.12.1 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.[28]

- 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.
- 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.
- For units greater than 30 MW output, the NO_X emission standard is 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.

Compliance with the NO_X emission limit is determined on a 4-hour rolling average basis.[29] After modification, these NSPS Subpart KKKK requirements will replace the NSPS Subpart GG requirements for turbines T1 - T4 established in 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).[30]

4.3.12.2 Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment must be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

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[27] 40 CFR 60.4315

[28] Table 1 to Subpart KKKK of Part 60

[29] 40 CFR 60.4350(g), 40 CFR 60.4380(b)(1)

[30] 40 CFR 60.4330(a)(1) or (a)(2), respectively

4.3.12.2.1 NO_X Compliance Demonstration Requirements

The T1 - T4 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. Units T1 through T4 will operate without water injection during periods of natural gas combustion and with water injection during periods of fuel oil combustion. In both cases, compliance with the NO_X emission limit can be demonstrated through the use of a NO_X-diluent CEMS to determine the hourly NO_X emission rate in ppm.[31] Pursuant to 40 CFR 60.4345, the Facility can rely on its existing NO_X CEMS installed and certified according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS Subpart KKKK NO_X emission limits.

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.[32] 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 relative accuracy test audit (RATA) to the NO_X emission limit under this subpart.[33]

4.3.12.2.2 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.[34] 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.[35]

However, as allowed per 40 CFR 60.4365, OPC 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) 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.

OPC 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,

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[31] 40 CFR 60.4335(b)(1) and 40 CFR 60.4340(b)(1)

[32] 40 CFR 60.4340(b), 40 CFR 60.4405

[33] 40 CFR 60.4405(c) and (d)

[34] 40 CFR 60.4370(b) and (c)

[35] 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

tariff sheet, or transportation contract for the gaseous fuel, specifying that the maximum sulfur content does not exceed its excursion threshold of 0.16 grains per 100 standard cubic feet.[36] 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.

Under the proposed project, T1 - T4 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), OPC will now be required to monitor the sulfur content of the fuel oil burned in the combustion turbines or receive certification from the fuel supplier that the sulfur content is less than 0.05%.

4.3.12.3 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.

4.3.13 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.[37] The existing simple-cycle combustion turbines at the Facility each have peak heat input capacities greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, stationary combustion turbines T1 - T4 could potentially be subject to the provisions of NSPS TTTT.

However, 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 significantly less than 50% of the capital cost of a comparable new unit, therefore this proposed project does not meet the definition of reconstruction. As the combustion turbines at OPC are existing units and the proposed project does not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.[38] Under EPA's recently proposed revisions to NSPS Subpart TTTT, modified stationary combustion turbines would continue to not be subject to Subpart TTTT. [39]

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[36] Permit No. 4911-263-0013-V-07-0, Condition 6.1.7.c.i

[37] 40 CFR 60.5509(a)

[38] 40 CFR 60.5509(a)

[39] https://www.epa.gov/stationary-sources-air-pollution/nsps-ghg-emissions-new-modified-and-reconstructed-electric-utility

4.3.14 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 Talbot Energy Facility is presently classified as an area source of HAP emissions and will remain so following the proposed project. The determination of applicability to NESHAP requirements for the proposed project is detailed in the following sections. Rules that are specific to certain source categories unrelated to the proposed project 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.

4.4.3 40 CFR 63 Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines

NESHAP Subpart ZZZZ, *NESHAP for Stationary Reciprocating Internal Combustion Engines,* applies to Reciprocating Internal Combustion Engines (RICE) at major and area sources of HAP. The new diesel fired emergency fire pump (FP1) meets the definition of a RICE will be subject to NESHAP Subpart ZZZZ. However, per 40 CFR 63.6590(c), a new stationary RICE located at an area source of HAP that will be subject to regulations under 40 CFR Part 60, does not have any further requirements under NESHAP Subpart ZZZZ. As FP1 will be subject to NSPS Subpart IIII as discussed in Section 4.3.10, no further requirements apply under NESHAP Subpart ZZZZ.

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[40] 40 CFR 63.6080

4.4.4 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.

4.4.5 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 Facility is an area source, NESHAP Subpart UUUUU will not apply. Additionally, the Facility's simple-cycle combustion turbines are not steam generating units as defined in 40 CFR 63.10042.

4.4.6 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:

> *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 or installed as part of the proposed project.

4.4.7 Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The potential 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 project.

4.5 Compliance Assurance Monitoring

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), subject 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

[41] 40 CFR 63.7480

[42] 40 CFR 63.9980

[43] 40 CFR 63.11193

device to achieve compliance with an emission limit and whose pre-control emissions exceed the major source 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.

Presently, all six of the Facility's simple-cycle combustion turbines use dry low NO_X combustors when firing natural gas, and units T5 and T6 use water injection for NO_X control when firing fuel oil. EPD has previously determined that 40 CFR 64 is not applicable for any of the Facility's combustion turbines, even when using water injection, as each unit uses NO_X CEMS to verify proper operation.[44] Per 40 CFR 64.2(b)(1)(vi), use of a continuous compliance demonstration exempts a unit from the CAM requirements.

Following the completion of the proposed project, units T1 – T4 will continue to use dry low NO_X combustors for periods of natural gas firing and will use water injection for NO_X control during periods of fuel oil firing, similar to units T5 and T6. Each combustion turbine will continue to be operated with NO_X CEMS to verify proper operation. Therefore, the Facility's combustion turbines will continue to not be subject to the requirements of CAM following the completion of the proposed project.

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 store any of the listed chemicals in excess of the applicable threshold quantity, nor is it currently anticipated that the threshold quantity will be exceeded for any chemical stored after the completion of the proposed project. Therefore, the facility is not currently and is not anticipated post-project to be subject to 40 CFR 68 Subpart B.

4.7 Clean Air Markets Regulations

Starting with the 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 the Facility are:

- Acid Rain Program (ARP) – 1990 - ongoing
- Cross-State Air Pollution Rule (CSAPR) – 2015 (ongoing)

4.7.1 Acid Rain Program

In order to address 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. 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

[44] See Section V.C of the narrative issued by the Georgia EPD for Title V Permit No. 4911-263-0013-V-07-0, issued February 1, 2021.

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, OPC 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. 4911-263-0013-V-07-0. The proposed project should not alter any applicable requirements of ARP to the OPC 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.

4.7.2 Cross-State Air Pollution Rule

The CSAPR was developed to require affected states to reduce emissions from power plants that can contribute to ozone and/or particulate matter emissions.[45] 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.

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). Georgia is subject to CSAPR programs for both fine particles (SO_2 and annual NO_X) and ozone (ozone season NO_X).[46]

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402.[47] 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. OPC'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. OPC will continue to maintain sufficient allowances under CSAPR for its operations.

4.8 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.[48] This section reviews the source specific requirements for the proposed project and does not detail generally applicable requirements such as payment of permit fees.

4.8.1 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

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[45] https://www.epa.gov/interstate-air-pollution-transport/interstate-air-pollution-transport

[46] https://www.epa.gov/csapr/states-are-affected-cross-state-air-pollution-rule-csapr

[47] 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.

[48] Current through rules and regulations filed through June 21, 2023. http://rules.sos.ga.gov/gac/391-3-1

discretion of the Director. The Facility's turbines are subject to this regulation, and the proposed fire pump engine will be subject to this regulation.

The proposed project does not alter the applicable requirements of Rule (b), and OPC will continue to comply with Rule (b) via the combustion of pipeline quality natural gas and ULSD.

4.8.2 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:[49]

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

The combustion turbines and fire pump engine are used for the generation of electric and mechanical power, respectively, 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).

4.8.3 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 and fire pump engine at OPC are not subject to this regulation.

4.8.4 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 just "fuel-burning equipment," this regulation presently applies to the combustion turbines. The fuel sulfur content is limited to not more than 3% by weight for fuel-burning sources with a heat input capacity greater than 100 MMBtu/hr and to not more than 2.5% by weight for sources with a heat input capacity less than 100 MMBtu/hr.[50] The proposed project does not alter the applicable requirements of Rule (g) for the four modified combustion turbines, and OPC will comply with Rule (g) for the four modified combustion turbines via the combustion of pipeline quality natural gas and ULSD. For T1 - T4, this limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK. The proposed emergency fire pump engine will comply with the requirements of Rule (g) through the exclusive use of ULSD fuel.

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

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

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

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. OPC will continue to take the appropriate precautions to prevent fugitive dust from becoming airborne, including during periods of construction.

4.8.6 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 tanks are not subject to the requirements of Rule (bb).

4.8.7 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 tanks are fixed roof tanks and not external floating roof tanks, Rule (nn) will not apply.

4.8.8 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. The Facility is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[51]

4.8.9 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 this project on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, is provided in Volume II of this application.

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

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. Talbot County is not a listed county; therefore, Rule (vv) does not apply to the proposed fuel oil storage tanks.[52]

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

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

4.8.11 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. The Facility is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[53]

4.8.12 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. The Facility is not located within the geographic area covered by this rule.[54] Further, the Facility does not operate electric utility steam generating units. Therefore, Rule (jjj) is not applicable.

4.8.13 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. The Facility is not located within the geographic area covered by this rule, nor does it operate fuel-burning equipment with heat input capacities between 10 and 250 MMBtu/hr. Therefore, this regulation does not apply.[55]

4.8.14 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. The Facility is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[56]

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

Rule (nnn) limits NO_X emissions from stationary gas turbines used to generate electricity. The Facility is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.[57]

4.8.16 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. The Facility is not located within the geographic area covered by this rule, and is, therefore, not subject to this regulation.[58]

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

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

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

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

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

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

4.8.17 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. The Facility is not subject to this regulation, because none of its units are listed in the regulation.

4.8.18 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. The Facility is not subject to this regulation, because none of its units are listed in the regulation.

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

The proposed project will require physical construction activities to complete the proposed modifications. Potential emissions associated with the proposed project is above the *de minimis* construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i).[59] Further, as discussed in Section 4.1, PSD permitting is required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix F.

4.8.20 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, OPC Talbot is a Title V major source. The Facility currently operates under Permit No. 4911-263-0013-V-07-0. 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.

4.8.21 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

4.8.22 Non-Applicability of Other GRAQC

A thorough examination of the GRAQC applicability to the proposed project reveals many GRAQC that do not currently apply, will not apply once the proposed modification is complete, and do not impose additional

[59] 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.

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 project.

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, new storage tanks, and new emergency fire pump engine. Based on the BACT review, OPC proposes the technology and limits presented in Table 5-1 as BACT for the modified and new units.

Table 5-1. Summary of Proposed BACT Limits

Unit	Pollutant	Fuel	Selected BACT	Emission / Operating Limit	Compliance Method
Simple Cycle Combustion Turbines (T1 -T4)	NO_X	Natural Gas	DLN Combustors and Good Combustion and Operating Practices	12.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	CEMS
		Fuel Oil	Water Injection and Good Combustion and Operating Practices	42.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	156.8 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	0.0137 lb/MMBtu - Equivalent to 16.2 lb/hr	Performance Test
		Fuel Oil		0.017 lb/MMBtu - Equivalent to 23.2 lb/hr	
	CO	Natural Gas	Good Combustion and Operating Practices	8.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	CEMS
		Fuel Oil		15.0 ppmvd at 15% O_2 on a 3-hour rolling average basis	
		Both	Secondary BACT	97.1 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	N/A	Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices	313,253 tpy CO_2e per rolling 12-months (each CCCT)	Records of Fuel Usage
Each Fuel Oil Storage Tank	VOC	N/A	Good Operating and Maintenance Practices, Submerged Fill Pipe, Paint Colors with Low Solar Absorptance		N/A
Emergency Fire Pump	NMHC + NO_X	ULSD	Good Combustion Practices, Limiting Hours of Operation, Use of Clean Fuel (ULSD)	4.0 g/kW-hr (3.0 lb/hp-hr)	Purchase of a Certified NSPS IIII Engine
	Filterable PM/Total PM_{10}/Total $PM_{2.5}$	ULSD		0.54 g/kW-hr (0.40 lb/hp-hr)	
	CO	ULSD		11.4 g/kW-hr (8.5 lb/hp-hr)	
	GHGs	ULSD		N/A	

5.1 BACT Requirement

The BACT requirement applies to each new or modified emission unit from which there is an increase in emissions of pollutants subject to PSD review. OPC 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 four modified simple-cycle combustion turbines, two new storage tanks, and one new emergency fire pump engine. 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).[60]

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[60] 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.[61]

..*design, equipment, work practice, operational standard, or combination thereof* ..

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 (e.g., use of low-sulfur diesel) 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 project 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.[62] 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.* [63]

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

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

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

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.[64] 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 energy, environmental, and/or economic impacts indicate 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 "top-down" approach 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.

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."*[65]

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*

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

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

which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.[66]

More recently, this issue was addressed for GHG BACT:[67]

> *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.*[68]

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:[69]

> *"…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 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 achievable 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.

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[66] 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.

[67] 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

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

[69] 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.

In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."[70]

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).[71] 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 CO, VOC, $PM/PM_{10}/PM_{2.5}$, or GHGs and thus there is no floor of allowable BACT limits for those pollutants.[72]

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*.[73] 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 project:

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[70] 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.

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

[72] As discussed in Section 4.3.13, NSPS Subpart TTTT does not regulate modified combustion turbine systems.

[73] 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[74]
- 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[75]
- 2010 Group Reports from the Clean Air Act Advisory Committee, Climate Change Work Group[76]

5.4 BACT "Top-Down" Approach

The following sections present the top-down BACT analysis for each pollutant for which this project triggers PSD and is specific to each emission unit, unless otherwise specified. The five steps in such an evaluation can be summarized as follows:[77]

- **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.

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.
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.

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[74] 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.

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

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

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

Trinity Consultants reviewed recently issued air permits and permit files and performed searches of the RBLC database in May 2023 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 Talbot Energy Facility, only combustion turbine units with potential generating capacities larger than 100 MW were considered.[78] For combustion turbines, the following categories were searched:[79]

- Permit Data between 1/1/2013 and 05/26/2023
- Process Types[80]
  - 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 E presents summary tables of relevant BACT determinations for the above emission units. While not in the RBLC database, OPC is including information for a similar project, which was recently permitted by the EPD:

[78] 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.

[79] 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.

[80] 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.

- Washington County Power facility in Sandersville, GA[81]

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.

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 typically demonstrated and considered technically feasible.[82]

5.4.2.2 Emerging and Undemonstrated Technology

An undemonstrated technology may only be considered 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."[83] 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."[84] 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 BACT limit. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, 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 for purposes of setting the BACT limit.

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[81] A portion of the Washington County Power facility, including two of the facility combustion turbines, and ancillary equipment, were sold to OPC.

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

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

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

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 method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.[85]

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 8.25% was used as the current Bank Prime Rate based on U.S. Federal Reserve data.

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

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[85] U.S. EPA, *OAQPS Control Cost Manual*, 7th edition, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

the imposition of an emissions limit infeasible, in which case a work practice or operating standard can be imposed.

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 redefine the nature of the source is not appropriate in a BACT determination.

As U.S. EPA notes, a key task for the reviewing agency is to determine which parts of the proposed project 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.*[86]
>
> …
>
> *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.*[87]

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.* [88]

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

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

[88] 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.[89]

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

The Facility presently operates six existing simple-cycle combustion turbines. Four of the combustion turbines (T1 – T4) are fired exclusively on natural gas, and the remaining two combustion turbines (T5 and T6) are fired primarily on natural gas with fuel oil as a back-up fuel. OPC is proposing the addition of fuel oil combustion capability for the four existing natural gas-fired combustion turbines (T1 – T4) to enhance system reliability and to provide support and meet demand during times of natural gas supply curtailment and interruption. This project requires physical modifications to each of the four turbines, installation of fuel oil storage capacity, and installation of a diesel-fired emergency fire pump engine. OPC is requesting permit conditions limiting total annual operations on either fuel to no more than 4,200 hours per year for each of the four modified combustion turbines, of which up to 450 hours per year per unit can be used for firing fuel oil. The proposed fuel oil storage capacity on-site could be as much as a 3.16 million gallons divided between two, vertical fixed-roof storage tanks (storage capacity of 1.58 million gallons for each new tank). The emergency fire pump engine is proposed as 455 hp using fuel oil and operating up to 500 hours per year. OPC proposes to continue operating Dry Low NO_X burners on the four modified turbines during gas combustion and proposes to install and operate a water-injection system to minimize the formation of NO_X emissions during fuel oil combustion.

During gas combustion at 100% operating load, the estimated heat input capacity is estimated to be 1,180 MMBtu/hr for each of the four modified turbines, whereas during fuel oil combustion at 100% operating load, the heat input capacity is estimated to be 1,365 MMBtu/hr for each of the four modified turbines. Collectively, the four modified turbines will each continue to maintain a 108-MW capacity. OPC 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. The Talbot Energy Facility will continue to operate as a peaking plant, 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

[89] *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.

most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X.[90] 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.

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).[91] Most thermal NO_X is formed in high temperature flame pockets downstream from the fuel injectors.[92] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NO_X is formed readily.[93] 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.[94] 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.[95]

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.[96] Most distillate oils have nitrogen content less than 0.015 percent by weight, resulting in more fuel NO_X generation than natural gas.[97]

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 OPC. 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):

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

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

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

[93] 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.

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

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

[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.

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 Facility's combustion turbines are each 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 to inherently lower NO_X emission levels. Therefore, the RBLC review was limited to units of comparable size. For conservatism, OPC focused on units of approximately 100 Megawatts (MW) in size or greater.[98]

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 project, 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 Facility's 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 E. 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:[99]

- 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:

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

99 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.

- 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 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.[100] 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.[101]

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.[102] 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.[103] 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.[104] Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

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

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

[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.

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).[105] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[106] 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.[107]

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.[108]

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.[109] 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.[110] 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,

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[105] 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

[106] 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

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

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

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

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

reducing the NO_X removal efficiency.[111] 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.[112]

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 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).[113]

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.[114] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[115] 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.[116]

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[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] 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.

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

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

[116] 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.

The ability of the METEOR™ catalyst to reduce NO_X emissions is on par with more traditional SCR designs.[117]

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.

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.[118] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[119] As the OPC 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 OPC 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™/$SCONO_X$™ Technology Feasibility

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

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117 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.

118 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.

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 page 12.

several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[120] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[121]

Consequently, it is concluded that EMx™/SCONOx™ is not technically feasible for control of NO_X emissions from the Facility's turbines.

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.[122] 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.[123] 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 OPC'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.[124] In addition, this technology is essentially SCR with a focus on reducing ammonia slip; accordingly, as SCR has been deemed infeasible in Step 4, and 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 Facility's turbine units.[125] 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

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[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 pages 14.

[121] 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.

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

[123] The Facility's turbine exhaust temperatures are represented as 994°F in the Facility's Title V Renewal Application, dated December 5, 2019 (Submittal ID: TV-420162).

[124] 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.

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

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 Facility's 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.[126,127] A review of the RBLC database for turbines similar to the Facility's units did not return any units that use the 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 four combustion turbines proposed to be modified as part of the proposed project 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 Facility's four modified simple-cycle turbines is more than $23,000 per ton of NO_X removed based on the detailed cost

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[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 16.

[127] 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.

analysis provided in Appendix D, developed using the methods outlined by the U.S. EPA in the OAQPS guidance manual.[128] 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 effective operation of the SCR. Therefore, OPC concludes that SCR is not cost effective and is not considered BACT for the Facility's modified turbines.

For periods of fuel oil combustion, the next highest ranked control system is a water or steam injection system. OPC 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.

For periods of 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 four modified combustion turbine systems will be subject to an NSPS Subpart KKKK NO_X emission standard of 15 ppm at 15% O_2 during natural gas combustion; for fuel oil combustion, the NO_X emissions standard will be 42 ppm at 15% O_2; and a NO_X emissions standard of 96 ppm at 15% O_2 applies when operating at less than 75% of peak load or at ambient temperatures below 0 °F. These NSPS Subpart KKKK limits serve as the floor for allowable NO_X BACT limits. The four modified combustion turbines will no longer be subject to NSPS Subpart GG following completion of the proposed project.[129] Each turbine is also already subject to a 12 ppm at 15% O_2 NO_X emissions limit under Condition 3.3.7.a of Permit No. 4911-263-0013-V-07-0, which is more stringent than the NO_X standard established under NSPS KKKK limit.

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, OPC searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as BACT emission limits for comparable operations. Numerous entries for natural gas or fuel oil simple-cycle combustion turbines are provided in the RBLC summary table in Appendix E. 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 E provides an indication of what has been established as BACT emission limitations for potentially similar units as those being modified by OPC. 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

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[128] U.S. EPA, *OAQPS Control Cost Manual*, 7th edition, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

[129] 40 CFR 60.4305(b)

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 OPC are those which include turbine units deemed to be potentially modified. A review of the RBLC database entries listed in Appendix E 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 Facility's turbines include:

- (A) Turbine is existing and proposed a modification, excluding units proposed for initial construction;
- (B) 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);
- (C) Units are similar to Siemens units; and
- (D) 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 Talbot Energy 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 Facility. Findings and notes from this research are further detailed in Sections 5.6.6.1.1 through 5.6.6.1.14.

Note that Washington County Power in Sandersville, GA is not in the RBLC database but was considered. The project is similar in nature to the project subject to this application; however, the units are GE models, and do not operate in the same manner as the Siemens models at Talbot for control of NO_X emissions. While it is feasible for the GE units at Washington County Power to meet a NO_X emission limit of 9 ppm, there would be issues with the Siemens units at Talbot meeting 9 ppm during various operational modes, as discussed further below. For this reason, though the project and units are similar, the emissions are not directly comparable.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	NO_X Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Westar Energy – Emporia Energy Center[3]	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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[3]	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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	No – units were new (not modified) and were not similar to Siemens	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. 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	No – units were new; also project was cancelled	262 MW	Unknown	2.5	ppmvd @ 15% O_2	1-hr Avg.	One 262 MW gas turbine.

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	NO_X Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Waverly Facility	WV	1/23/2017	No – units were not similar to Siemens	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	No – units were not similar to Siemens	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[4]	LA	2/17/2017	No – units were constructed for the purposes of refrigeration compression rather than for power generation	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	No – units were new (not modified) and were not similar to Siemens	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	Yes, although units were new (not modified) they are Siemens; unclear if they are in operation	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	No – units were new (not modified) and were not similar to Siemens	Unknown	GE 7FA	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.

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	NO_X Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Lake Charles LNG Export Terminal	LA	9/3/2020	No – units were not designed power generation; units are not yet proven, project has not been initiated	Unknown	Unknown	3.1	ppmvd @15%o2	3-hour average	Low NOx burners and SCR used, Turbines (EQT0020 — EQT0031).
Colbert Combustion Turbine Plant	AL	9/21/2021	No – units are not yet proven, project under construction	Three 229 MW Simple Cycle Combustion Turbines	Unknown	9.0	ppmvd	3 hour avg @ 15% O2	---
Nacero Penwell Facility	TX	11/17/2021	No – units are not yet proven, project has not been initiated	Unknown	Unknown	9.0	ppmvd	15% O2	Low NOx burners and SCR listed as control technologies.
Liquefaction Plant	AK	7/7/2022	No – units were not designed power generation; units are not yet proven, project has not been initiate	1113 MMBtu/Hr	Unknown	2.0	ppmv @ 15% o2	3-hours	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility. SCR, DLN combustors, and good combustion practices listed.
Tennessee Valley Authority - Johnsonville Combustion Turbine	TN	8/31/2022	No – units are not yet proven, project has not been initiated	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Unknown	5.0	ppmvd @ 15% o2	4-hour rolling average excluding startup/ shutdown	Dry low-NOx burners and selective catalytic reduction listed.
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified)	667 MMBtu/Hr	Unknown	25.0	ppm	4-hr rolling avg except <75% peak load	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.

[1] Potentially Comparable units have at least one aspect in common with the OPC units. Reasons for removal from comparison are detailed in the following sections of this report.

[2] 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.

[3] The RBLC database entries in Appendix E 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.

[4] 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.

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 Facility's turbine units. Additional details are included in these sections which were not available in the RBLC database entries.

5.6.6.1.1 Westar 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).[130] 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.[131] Aeroderivative turbines have a much smaller power output than what would be expected from a large frame unit such as those used at the Facility; 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 OPC. However, the GE 7FA and Siemens turbines would not have similar emission profiles. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, OPC maintains that the GE model turbines are not necessarily an appropriate comparison for a Siemens turbine.

5.6.6.1.2 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. The GE 7FA turbines would be considered comparable in size and age to the existing units operated by OPC. However, the GE 7FA and Siemens turbines would not have similar emission profiles. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, OPC maintains that the GE model turbines are not necessarily an appropriate comparison for a Siemens turbine.

5.6.6.1.3 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 Talbot Energy 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.[132] However, in 2018, the California Energy Commission terminated the 2015 application to construct the facility and the project

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

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

[132] 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.

was voided.[133] 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.

5.6.6.1.4 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.[134] 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.[135] 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.[136] 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.[137]

The authorization to operate the TurboPhase engines was removed by way of the Permit to Modify issued on March 13, 2018.[138] 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."[139]

The Waverly facility GE 7FA turbines have been modified since installation, albeit in ways that are not like the proposed OPC modifications. The GE 7FA turbines would be considered comparable in size and age to the existing units operated by OPC. However, the GE 7FA and Siemens turbines would not have similar emission profiles. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, OPC maintains that the GE model turbines are not necessarily an appropriate comparison for a Siemens turbine.

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[133] 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).

[134] 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.

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

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

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

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

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

5.6.6.1.5 Cameron LNG Facility

On October 1, 2013, the Cameron LNG Facility was issued an initial PSD permit and revised Title V permit, authorizing the construction of additional equipment which included six refrigeration compressor turbines with heat inputs of 1,069 MMBtu/hr each.[140] 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.[141] 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.[142] 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 Talbot Energy Facility. Therefore, the Cameron LNG Facility RBLC database entry is not considered further in these BACT analyses.

5.6.6.1.6 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.[143] Because the turbine was built in 2013, the equipment at the Mustang Station represents new turbines. The GE 7FA turbine would be considered comparable in size to the existing units operated by OPC. However, the GE 7FA and Siemens turbines would not have similar emission profiles. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, OPC maintains that the GE model turbines are not necessarily an appropriate comparison for a Siemens turbine.

5.6.6.1.7 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.[144] An initial permit was issued by the TCEQ on February 2, 2018.[145] Based on further investigation, it is unclear if the Jackson County Generating Facility ever completed the install and commissioning of the new simple-cycle turbines, therefore the BACT limit has not been demonstrated in practice and the associated RBLC database entry is not considered further in these BACT analyses.

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

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

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

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

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

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

5.6.6.1.8 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.[146] 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 be comparable to the existing OPC units.

5.6.6.1.9 Lake Charles LNG Export Terminal

The Lake Charles LNG Export Terminal was issued initial permits for the construction of 12 turbines on September 3, 2020.[147] The permit allowed for the construction of 12 combustion turbines, however the output, make and model of the turbines are unknown. Each of the turbines were to be controlled using SCR and Low NOx burners. Upon further investigation, as of April 2023, it is believed that the Lake Charles LNG Export Terminal has not yet been finalized and is not currently operating. In addition, the units were not designed for the purposes of power generation. Therefore, the Lake Charles LNG Export Terminal RBLC database entry is not considered further in these BACT analyses.

5.6.6.1.10 Colbert Combustion Turbine Plant

The Tennessee Valley Authority Colbert Combustion Turbine Plant was issued initial permits for the construction of three simple-cycle turbine generating units on September 21, 2021.[148] The permit allowed for the construction of three GE model 7F.05 simple-cycle combustion turbines capable of generating 229 MW of output each. Each of the turbines were to be controlled using DLN burners. The GE 7F.05 and Siemens turbines would not have similar emission profiles. Given the unique emission profiles associated with the manufacturer design of different natural gas simple-cycle turbine units, OPC maintains that the GE model turbines are not necessarily an appropriate comparison for a Siemens turbine. Further, the units have not begun operation and have not demonstrated compliance with the proposed limits.

5.6.6.1.11 Nacero Penwell Facility

The Nacero Penwell Facility was issued initial permits for the construction turbine units on November 17, 2021.[149] After further investigation, it was found that the Nacero Penwill facility has not yet been built; therefore, the facility RBLC database entry is not considered further in these BACT analyses.

5.6.6.1.12 Liquefaction Plant

The Liquefaction Plant was issued initial permits for the construction of six simple-cycle turbines on July 7, 2022.[150] The permit allowed for the construction of six turbines capable of generating 115 MW of output. Each of the turbines were to be controlled using DLN burners plus SCR. On April 13, 2022, AGDC provided

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

[147] Permits Nos. 212290 and PSD-LA-838 issued by the LDEQ to Lake Charles LNG Export Company on September 3, 2020.

[148] Permits No. 701-0010 issued by the ADEM to Tennessee Valley Authority on September 21, 2021.

[149] Permits Nos. 164137 and PSDTX1594 issued by the TCEQ to Nacero Penwell Facility on November 17, 2021.

[150] Permits No. AQ1539CPT01 issued by the ADEC to Alaska Gasline Development Corporation on July 7, 2022.

the Department with an application addendum revising their NO_X BACT proposal for the gas fired turbines. The new proposal recommends the top NO_X emissions control of SCR with an emission limit of 2 ppmv at 15% O_2. After further research, the Liquefaction Plant is still undergoing construction and has not yet been completed. Therefore, since the plant is non-operational, the plant is not considered further in these BACT analyses.

5.6.6.1.13 Tennessee Valley Authority – Johnsonville Combustion Turbine

The Tennessee Valley Authority – Johnsonville Combustion Turbine facility was issued initial permits for the construction of ten simple-cycle turbine units on August 31, 2022.[151] The permit allowed for the construction of ten turbines capable of generating 465.8 MMBtu/hr of output. Each of the turbines were to be controlled using DLN burners and SCR. After further research, the Tennessee Valley Authority – Johnsonville Combustion Turbine project has not yet been completed. Therefore, since the plant is non-operational, and would utilize SCR to meet its emission limit (which has been found cost ineffective for this project), the plant is not considered further in these BACT analyses.

5.6.6.1.14 LBWL – Erickson Station

The LBWL Erickson Station was issued initial permits for the construction of one simple-cycle turbine generating unit on December 20, 2022.[152] The permit allowed for the construction of a nominally rated 667 MMBtu/Hr combustion turbine. 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 be comparable to the existing OPC units. The proposed NO_X emission limit (25 ppm) is also much higher than the current emission limit for the Facility's combustion turbines during periods of natural gas combustion. Further, it is unclear if the units have begun operation or demonstrated compliance with the proposed limits.

5.6.6.1.15 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 OPC units. Table 5-4 summarizes those RBLC listings that are comparable (i.e., modification of an existing unit), the turbine involved was a Siemens turbine or of similar design, and the operations were for power generation. Projects that have yet to be completed were not evaluated further, as they are not operational and thus have not demonstrated compliance with their proposed BACT limits.

[151] Permits No. 979348 issued by the TDEC to Tennessee Valley Authority on August 31, 2022.

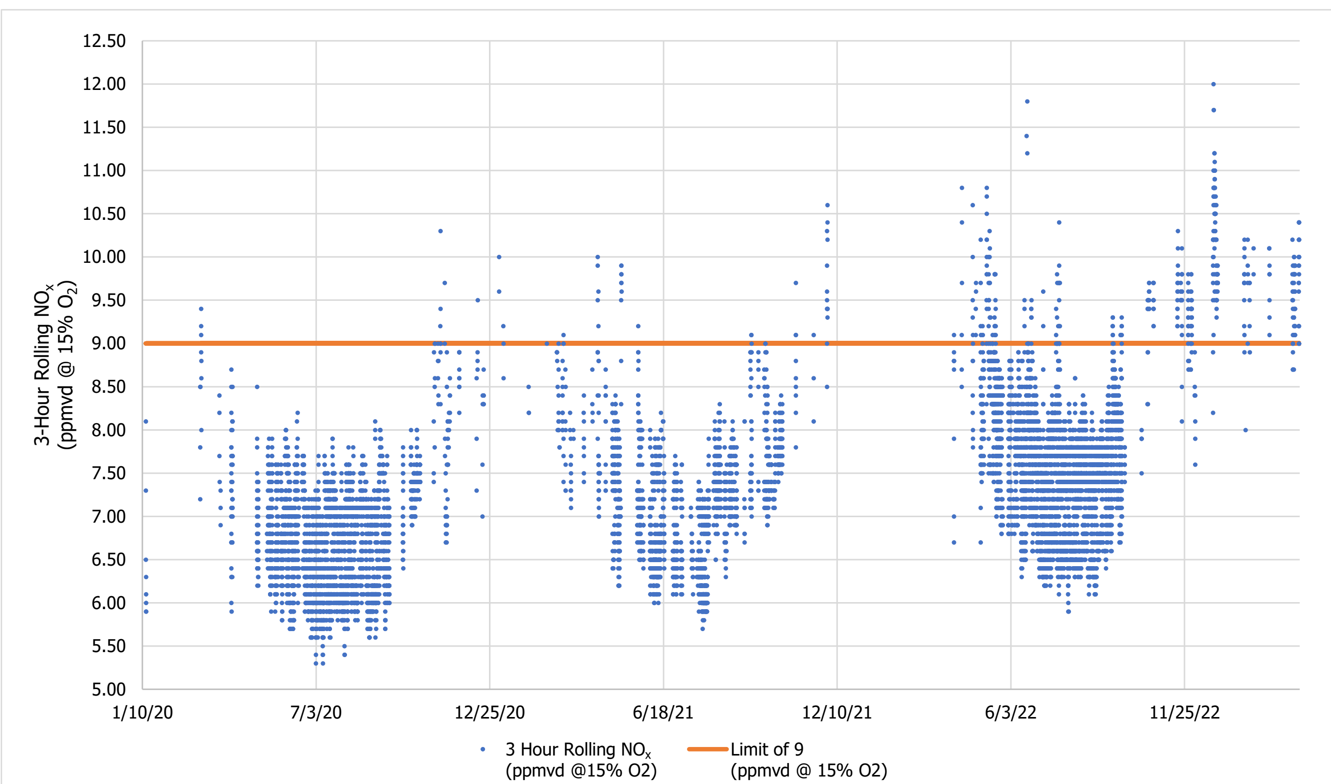
[152] Permits No. 74-18D issued by the Michigan AQD to Lansing Board of Water and Light on December 20,2022.

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

Site	Modification?	Siemens Turbine?	Control Technology?
Jackson County Generators	No	Yes, Siemens	DLN
Washington County Power	Yes	No, GE	DLN

The units that are comparable are due to the type of control technology employed (i.e., DLN burners). However, the BACT limits (9 ppmvd at 15% O_2, on a 4-hr average, during periods of natural gas firing) proposed for these units are not possible for the Talbot Energy Facility units on a consistent basis while firing natural gas. The following figure summarizes the variation in emissions from the Facility's combustion turbines T1-T4 over time, which are consistently below the current permit limit of 12 ppmvd at 15% O_2, but are unable to consistently achieve a limit as stringent as 9 ppmvd at 15% O_2.

Figure 5-1. OPC Talbot Turbines 1-4 NO_X Emissions from Natural Gas Combustion (2020-2022) Excluding Periods of Startup/Shutdown



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. However, a NO_X limit of this level is not an achievable emission limitation for the turbine units at the Talbot Energy Facility. Even so, the use of DLN technology reduces NO_X emissions by a considerable amount over traditional burner technology. **Therefore, OPC proposes a BACT limit for NO_X of 12 ppmvd at 15% O_2 on a 3-hr averaging basis when firing natural gas, excluding periods of startup and shutdown.** A 3-hr averaging period as documented per CEMS is proposed for consistency with the monitoring requirements under the Facility's current permit and to ensure OPC'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 Talbot Energy 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 Facility. Findings and notes from this research are further detailed in Section 5.6.6.1.4. Note that Washington County Power in Sandersville, GA is not in the RBLC database but was considered. When fuel oil is used, a similar level to the Washington County Power unit is achievable. This limit is 42 ppm at 15% O_2 on a 4-hour rolling average. Compliance monitoring, as for natural gas combustion, will be accomplished via use of CEMs.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	NO_X Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Hill County Generating Facility	TX	4/7/2016	Yes – some units are Siemens	Between 684 and 928 megawatts (MW)	GE 7FA and Siemens SGT6-5000	42.0	ppmvd @15% O2	3-hr rolling average	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 Siemens SGT6- 5000(5). Electric output is between 684 and 928 megawatts (MW)
Waverly Facility [3]	WV	1/23/2017	No – units were not similar to Siemens	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 [3]	WV	3/13/2018	No – units were not similar to Siemens	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] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 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 those RBLC listings that are comparable; i.e., modification of an existing unit, the turbine involved was a Siemens turbine or of similar design, and the operations were for power generation. Projects that have yet to be completed were not evaluated further, as they are not operational and thus have not demonstrated compliance with their proposed BACT limits.

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

Site	Modification?	Siemens Turbine?	NO_X Emission Limit	Averaging Period
Hill County Generating Facility	No	Yes, Siemens	42 ppmvd @15% oxygen	3-hr average
Washington County Power	Yes	No, GE	42 ppmvd @15% oxygen	4-hr average

The potentially comparable turbine units listed in Table 5-6 are identical to the BACT floor limitation established per NSPS Subpart KKKK (i.e., 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 OPC turbines when combusting fuel oil. Compliance with the limit is proposed to be determined on a 3-hour rolling average basis, consistent with the existing limits in the Facility's permit for units T5 and T6 when firing fuel oil. **As such, OPC proposes a BACT limit for NO_X of 42 ppmvd at 15% O_2 on a 3-hour rolling average basis when firing fuel oil, excluding periods of startup and shutdown**. Compliance will be demonstrated via CEMS.

5.6.6.3 Secondary BACT Limit – NO_X

The proposed primary BACT limits of 12 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. OPC therefore proposes a secondary BACT limit per turbine of 156.8 tpy on a rolling 12-month basis, inclusive of all operational conditions including startup and shutdown, 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 project is due to NO_X emissions from each combustion turbine. As OPC 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 from SO_2 resultant from this project will not be significant and is not addressed separately as part of this analysis. The use of pipeline quality natural gas and ultra-low sulfur diesel fuel will help to minimize SO_2 and secondary PM formation.

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.[153] 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:

- 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. 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). Multicyclones in parallel can typically handle a

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

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). 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.[154]

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.[155]

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 wet applications.[156] 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).[157]

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.[158] 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.

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

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

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

[157] 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.

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

Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[159]

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.[160]

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 SO_2 and H_2SO_4. Similarly, use of ultra-low sulfur diesel fuel oil also minimizes SO_2 and 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.

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 controlling filterable particulate emissions 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.[161]

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

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

[161] 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.

5.7.4 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.

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

The four modified 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, OPC 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 E. 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 OPC. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix E to identify potentially comparable units to the OPC turbines:

- Turbine is existing and proposed for a modification, excluding units proposed for initial construction;
- Units are similar Siemens 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 Talbot Energy Facility.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	PM Emission Limit [2]	Units [2]	Notes
Westar Energy – Emporia Energy Center	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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. Limit equates to nominal 0.015 lb/MMBtu.
Westar Energy – Emporia Energy Center	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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. Limit equates to nominal 0.044 lb/MMBtu.
Pueblo Airport Generating Station	CO	5/30/2014	No – units were new (not modified) and were not similar to Siemens	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. Limit equates to nominal 0.013 lb/MMBtu.
Doswell Energy Center	VA	10/4/2016	No – units were new; also project was cancelled	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	No – units were not similar to Siemens	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. Limit equates to nominal 0.01 lb/MMBtu.
Waverly Power Plant	WV	3/13/2018	No – units were not similar to Siemens	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.

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	PM Emission Limit [2]	Units [2]	Notes
Cameron LNG Facility	LA	2/17/2017	No – units were constructed for the purposes of refrigeration compression rather than for power generation	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	No – units were new (not modified) and were not similar to Siemens	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	Yes, although units were new (not modified) they are Siemens; unclear if they are in operation	230 MW for Each Turbine	Siemens	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 [3]	TX	8/17/2020	No – units were new (not modified) and were not similar to Siemens	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.
Lake Charles LNG Export Terminal	LA	9/3/2020	No – units were not designed power generation; units are not yet proven, project has not been initiated	Unknown	Unknown	-	-	No limits provided for PM.
Colbert Combustion Turbine Plant	AL	9/21/2021	No – units are not yet proven, project under construction	Three 229 MW Simple Cycle Combustion Turbines	Unknown	0.008 (TPM_{10} and $TPM_{2.5}$)	lb/MMBtu	3-hr average.
Nacero Penwell Facility	TX	11/17/2021	No – units are not yet proven, project has not been initiated	Unknown	Unknown	0.0075 (FPM_{10})	lb/MMBtu	Good combustion practices and the use of gaseous fuel.
Liquefaction Plant	AK	7/7/2022	No – units were not designed power generation; units are not yet proven, project has not been initiate	1113 MMBtu/Hr	Unknown	0.007 (TPM, TPM_{10} and $TPM_{2.5}$)	lb/MMBtu	3-hr average; Good combustion practices and clean fuel (natural gas).
Tennessee Valley Authority – Johnsonville Combustion Turbine	TN	8/31/2022	No – units are not yet proven, project has not been initiated	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Unknown	3.65 (TPM)	lb/hr	Good combustion design and operating practices and the use of low sulfur fuel. Limit equates to nominal 0.008 lb/MMBtu.
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified)	667 MMBtu/Hr	Unknown	4.5 (TPM, TPM_{10} and $TPM_{2.5}$)	lb/hr	Hourly; Pipeline quality natural gas, inlet air conditioning and good combustion practices. Limit equates to nominal 0.007 lb/MMBtu.

[1] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 Talbot Energy Facility 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 Siemens 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. OPC already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing four turbine systems that would be modified under the proposed project.

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 Facility's units. Table 5-9 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a Siemens turbine, and whether the facilities in Table 5-8 are comparable to the OPC units based on these factors.

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

Site	Modification?	Siemens Turbine?	PM Emission Limit	Estimated lb/MMBtu
Jackson County Generators	No	Yes, Siemens	11.81 tpy	Not available
Washington County Power	Yes	No, GE	24.2 lb/hr (TPM, TPM_{10}, $TPM_{2.5}$)	0.0137

For the units detailed in Table 5-9 that are potentially comparable to the modified OPC units, one is in tons/yr and a conversion to a limit for total PM_{10}/total $PM_{2.5}$ in terms of lb/hr is not possible. 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 more comprehensive limit comparison, where information was readily available, an equivalent lb/MMBtu has been estimated in Table 5-8. Based on the available data, the nominal range of BACT limits for TPM/TPM_{10}/$TPM_{2.5}$ when combusting natural gas is between 0.005 – 0.044 lb/MMBtu for listed RBLC units.

When looking at the range of potential BACT limits (0.005 – 0.044 lb/MMBtu) and the heat input capacity of 1,180 MMBtu/hr for natural gas, the equivalent lb/hr rates would range from 5.9 – 52 lb/hr for total PM/PM_{10}/$PM_{2.5}$. As the lb/hr range for total PM encompasses the lb/hr based on the selected BACT limit, OPC is proposing a BACT value that is within the range of BACT limits within RBLC.

OPC is proposing a BACT emission limit for each modified turbine during periods of natural gas firing of 16.2 lb/hr for filterable PM and total PM_{10}/$PM_{2.5}$, equivalent to an emission rate of 0.0137 lb/MMBtu, excluding periods of startup and shutdown. 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 Talbot Energy Facility.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	PM Emission Limit [2]	Units [2]	Notes
Hill County Generating Facility	TX	4/7/2016	Yes – some units are Siemens	171 MW (ULSD)	GE 7FA and Siemens SGT6-5000	9.8 (TPM_{10}, $TPM_{2.5}$)	lb/hr	3-hr rolling ave; combustor designed for complete combustion and therefore minimizes emissions; 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.
Waverly Facility [3]	WV	1/23/2017	No – units were not similar to Siemens	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 [3]	WV	3/13/2018	No – units were not similar to Siemens	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.
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified)	667 MMBtu/Hr	Unknown	-	-	No limit. Good combustion practices, burn ultra-low diesel fuel, and be NSPS compliant.

[1] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 OPC units. Table 5-11 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a Siemens turbine, and whether the facilities in Table 5-10 are comparable to the OPC units based on these factors.

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

Site	Modification?	Siemens Turbine?	PM Emission Limit	Estimated lb/MMBtu
Hill County Generating Facility	No	Yes, Siemens	9.8 lb/hr (TPM_{10}, $TPM_{2.5}$)	Not available
Washington County Power	Yes	No, GE	26.8 lb/hr (FPM, TPM_{10}, $TPM_{2.5}$)	0.0142

For the units detailed in Table 5-11 that are potentially comparable to the modified OPC units, the limit for Hill County for total PM_{10}/total $PM_{2.5}$ is 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.

When looking at the range of potential BACT limits of 9.8 lb/hr to 39.0 lb/hr in all RBLC entries, as well as the 0.0142 lb/MMBtu value of the comparable unit, the value OPC is proposing as BACT is within this range.

For periods of fuel oil firing, OPC proposes a BACT emission limit for each modified simple-cycle system of 23.2 lb/hr for filterable PM and total $PM_{10}/PM_{2.5}$, equivalent to an emission rate of 0.017 lb/MMBtu, excluding periods of startup and shutdown. 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 result 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. 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 Catalyst

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 EMX™/SCONOX™

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.[162] 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

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

conservatively considered for the purposes of this evaluation to be 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.[163] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[164]

Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of CO emissions from the Facility's 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 OPC turbines is almost $23,000 per ton of CO 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.[165] 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, OPC 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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[163] 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.

[164] 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.

[165] U.S. EPA, *OAQPS Control Cost Manual*, 7th edition, 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 four modified simple-cycle combustion turbines will not be subject to any NSPS or NESHAP standard for CO, and thus, there is no floor of allowable CO BACT limits. The units are also not subject to any CO emission limit per the GRAQC.

As the selected BACT for CO emissions relies on the combustion process design and good combustion practices, OPC 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 E. 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 OPC. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix E to identify potentially comparable units to the OPC turbines include:

- Turbine is existing and proposed a modification, excluding units proposed for initial construction;
- Control method does not include control technologies which have been deemed to be infeasible (i.e., Oxidation Catalyst, $EM_X^{TM}/SCONO_X^{TM}$);
- Units are similar Siemens; 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 Talbot Energy Facility.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	CO Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Westar Energy – Emporia Energy Center	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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	No – units were new (not modified) and were not similar to Siemens	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	No – units were new (not modified) and were not similar to Siemens	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.
Waverly Facility	WV	1/23/2017	No – units were not similar to Siemens	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	No – units were not similar to Siemens	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.

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	CO Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Cameron LNG Facility	LA	2/17/2017	No – units were constructed for the purposes of refrigeration compression rather than for power generation	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 [3]	TX	8/16/2017	No – units were new (not modified) and were not similar to Siemens	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	Yes, although units were new (not modified) they are Siemens; unclear if they are in operation	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 [3]	TX	8/17/2020	No – units were new (not modified) and were not similar to Siemens	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.
Lake Charles LNG Export Terminal	LA	9/3/2020	No – units were not designed power generation; units are not yet proven, project has not been initiated	Unknown	Unknown	10	ppm @ 15% O_2	3-hr Avg.	A greenfield facility to liquefy and export natural gas.
Colbert Combustion Turbine Plant	AL	9/21/2021	No – units are not yet proven, project under construction	Three 229 MW Simple Cycle Combustion Turbines	Unknown	9	ppm @15% O_2	3-hr Avg.	Electric generating facility.
Nacero Penwell Facility	TX	11/17/2021	No – units are not yet proven, project has not been initiated, not a power facility	Unknown	Unknown	9	ppm @15% O_2	Unknown	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.
Liquefaction Plant	AK	7/7/2022	No – units were not designed power generation; units are not yet proven, project has not been initiated	1113 MMBtu/Hr	Unknown	5	ppm @15% O_2	3-hr Avg.	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaska's North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	CO Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Tennessee Valley Authority - Johnsonville Combustion Turbine	TN	8/31/2022	No – units are not yet proven, project has not been initiated, use of oxidation catalyst	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Unknown	5.0	ppm @15% O_2	4-hr avg.	Ten simple cycle natural gas turbines
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified), combined cycle units	667 MMBtu/Hr	Unknown	4	ppm @15% O_2	24-hr Avg.	The proposed new plant will be replacing the electrical generating capacity of both 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.
Hill County Generating Facility	TX	4/7/2016	Yes	171MW	GE 7FA and Siemens SGT6-5000	9	ppm @15% O_2	3-hr avg.	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).

[1] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 OPC 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. OPC already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. OPC 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 OPC units. Table 5-13 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a Siemens turbine, and whether the facilities in Table 5-12 are comparable to the OPC units based on these factors.

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

Site	Modification?	Siemens Turbine?	CO Emission Limit	Averaging Period
Jackson County Generators	No	Yes, Siemens	9 ppmvd @15% O_2	3-hr rolling average
Washington County Power	Yes	No, GE	9 ppmvd @15% O_2	3-hr rolling average
Hill County Generating Facility	No	Yes, Siemens	9 ppm @15% O_2	3-hr rolling average

As detailed in Table 5-13, potentially comparable engines combusting natural gas have CO emission limits of 9 ppmvd at 15% O_2 based on a 3-hour averaging period. Turbines 1-4 are capable of meeting a limit of 8 ppmvd CO at 15% O_2 when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas. OPC is proposing a limit over 10% lower than comparable units.

OPC proposes a BACT limit for CO of 0.0182 lb/MMBtu heat input (equivalent to 8 ppmvd at 15% O_2) on a 3-hr averaging basis when firing natural gas, excluding periods of startup and shutdown. OPC currently conducts and will continue to use continuous emissions monitoring via CEMS 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 Talbot Energy Facility.

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

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	CO Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Hill County Generating Facility	TX	4/7/2016	Yes – some units are Siemens	171 MW (ULSD)	GE 7FA and Siemens SGT6-5000	20.0	ppm @15% O_2	3-hr rolling avg.	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 Siemens SGT6-5000(5). Electric output is between 684 and 928 megawatts (MW).
Waverly Facility [3]	WV	1/23/2017	No – units were not similar to Siemens	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 [3]	WV	3/13/2018	No – units were not similar to Siemens	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.
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified) and combined cycle units	667 MMBtu/Hr	Unknown	4.0	ppm @15% O_2	24-hr rolling avg.	The proposed new plant will be replacing the electrical generating capacity of both 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.

[1] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 selected 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 for a modification of an existing unit, if the turbine involved was a Siemens turbine, and whether the facilities in Table 5-14 are comparable to the OPC units based on these factors.

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

Site	Modification?	Siemens Turbine?	CO Emission Limit	Averaging Period
Hill County Generating Facility	No	Yes, Siemens	20 ppmvd @15% O_2	3-hr rolling average
Washington County Power	Yes	No, GE	20 ppmvd @15% O_2	3-hr rolling average

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. Although the turbine units at the Hill County Generating Facility are proposed for construction and therefore cannot necessarily be considered directly comparable to the OPC turbine units, it is worth noting that the current Talbot Energy Facility emission limit for use of fuel oil (on Talbot Units 5 and 6) is 15 ppm CO at 15% O_2 during fuel oil combustion. As such, **OPC proposes a CO BACT emission limit for the four modified simple-cycle systems of 0.0364 lb/MMBtu heat input (equivalent to 15 ppmvd at 15% O_2) on a 3-hr averaging basis when firing fuel oil, excluding periods of startup and shutdown.** OPC currently conducts and will continue to use continuous emissions monitoring via CEMS 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 8.0 ppmvd and 15 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. OPC therefore proposes a secondary CO BACT limit per turbine of 97.1 tpy to ensure the minimization of emissions during startup/shutdown periods. This tpy limit would be inclusive of all operational scenarios, including startup and shutdown, for the combustion turbines.

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 result 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 Catalyst

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 exceeds 90%, but other pollutants such as benzene may not see any beneficial reductions. Hence, the overall range of VOC control can vary substantially.[166]

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.[167] 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 conservatively considered for the purposes of this evaluation to be technically feasible for installation on the Facility's combustion turbines and will be considered further in Step 4 to evaluate cost effectiveness.

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[166] 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.

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

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

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.[168] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[169]

Consequently, it is concluded that EM_X^{TM}/$SCONO_X^{TM}$ is not technically feasible for control of VOC emissions from the Facility's 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 is 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 OPC turbines is more than $177,000 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.[170] 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, OPC 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 VOC.

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[168] 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.

[169] 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.

[170] U.S. EPA, *OAQPS Control Cost Manual*, 7th edition, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

5.9.6 Selection of Emission Limits and Controls for VOC BACT – Combustion Turbines (Step 5)

The four modified simple-cycle combustion turbines will not be subject to any NSPS or NESHAP standard for VOC and thus there is no floor of allowable VOC BACT limits. The units are also not subject to any VOC emission limit per the GRAQC.

As the selected BACT for VOC emissions relies on the combustion process design and good combustion practices, OPC 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 E. 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 OPC. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix E to identify potentially comparable units to the OPC turbines:

- Turbine is existing and proposed a modification, excluding 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^{TM}/$SCONO_X^{TM}$);
- Units are similar to Siemens 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 Talbot Energy Facility.

Table 5-16. Natural Gas Fired Simple-Cycle Combustion Turbine VOC RBLC Data for Potentially Modified Units

Facility Name	State	Permit Issuance	Potentially Comparable?[1]	System Size	Turbine Model	VOC Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Westar Energy – Emporia Energy Center	KS	3/18/2013	No – units were new (not modified) and were not similar to Siemens	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	No – units were new (not modified) and were not similar to Siemens	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	No – units were new (not modified) and were not similar to Siemens	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	No – units were new; also project was cancelled	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	No – units were constructed for the purposes of refrigeration compression rather than for power generation	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 [3]	TX	8/16/2017	No – units were new (not modified) and were not similar to Siemens	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	Yes, although units were new (not modified) they are Siemens; unclear if they are in operation	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	Potentially Comparable?[1]	System Size	Turbine Model	VOC Emission Limit [2]	Units [2]	Averaging Period [2]	Notes
Ector County Energy Station [3]	TX	8/17/2020	No – units were new (not modified) and were not similar to Siemens	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.
Lake Charles LNG Export Terminal	LA	9/3/2020	No – units were not designed power generation; units are not yet proven, project has not been initiated	Unknown	Unknown	N/A	N/A	N/A	A greenfield facility to liquefy and export natural gas.
Hill County Generating Facility	TX	4/7/2016	Yes – some units are Siemens	171 MW (ULSD)	GE 7FA and Siemens SGT6-5000	5.4	lb/hr	Unknown	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 Siemens SGT6-5000(5). Electric output is between 684 and 928
Nacero Penwell Facility	TX	11/17/2021	No – units are not yet proven, project has not been initiated, non power generation units	Unknown	Unknown	1.7	Ppmvd	Unknown	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.
Liquefaction Plant	AK	7/7/2022	No – units were not designed power generation; units are not yet proven, project has not been initiated, use of oxidation catalyst	1113 MMBtu/Hr	Unknown	2	Ppm @15% O_2	3-hr Avg.	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.
LBLW Erickson Station	MI	12/20/2022	No – units were new (not modified), and combined cycle, use of oxidation catalyst	667 MMBtu/Hr	Unknown	3	ppm @15% O_2	1-hr	The proposed new plant will be replacing the electrical generating capacity of both 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.

[1] Potentially Comparable units have at least one aspect in common with the OPC units.

[2] 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.

[3] 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 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.

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 Facility's 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. OPC already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. OPC 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 OPC units. Table 5-17 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a Siemens turbine, and whether the facilities in Table 5-16 are comparable to the OPC units based on these factors.

Table 5-17. Unit Comparability for VOC Assessment – Natural Gas Firing

Site	Modification?	Siemens Turbine?	VOC Emission Limit	Averaging Period
Jackson County Generators	No	Yes, Siemens	2 ppmvd @15% O_2	Not Available
Washington County Power	Yes	No, GE	2 ppmvd @15% O_2	3-hr rolling average

As detailed in Table 5-17, potentially comparable engines combusting natural gas have VOC limits of 2 ppmvd @ 15% O_2. Additional research identified a Texas BACT document establishing 2.0 ppmvd as BACT for simple-cycle natural gas combustion turbines.[171]

Turbines 1-4 have a manufacturer emissions guarantee of 2 ppmvd VOC at 15% O_2 when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas. For compliance assurance purposes, **OPC therefore proposes a BACT limit for VOC as methane of 2.0 ppmvd at 15% O_2, excluding periods of startup and shutdown,** to be demonstrated via stack testing.[172]

5.9.6.2 Selection of Emission Limits for VOC BACT – Fuel Oil Firing

Table 5-18 includes the only VOC RBLC database entry (Hill County) for turbine units combusting fuel oil which may be potentially comparable to the existing units at the Talbot Energy Facility. This table is combined to the other comparable OPC units (Washington County Power).

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[171] Summary spreadsheet *Current BACT for All Combustion Units*, accessed June 2023. https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact-combustion.xlsx

[172] Method 25A for the determination of volatile organic compounds.

Table 5-18. Unit Comparability for VOC Assessment – Fuel Oil Firing

Site	Modification?	Siemens Turbine?	VOC Emission Limit	Averaging Period
Hill County Generating Facility	No	Yes, Siemens	3.3 lb/hr	Not given
Washington County Power	Yes	No, GE	5 ppmvd @15% O_2	3-hr average

As can be referenced in Table 5-18, Hill County is the only RBLC facility with turbine units which are potentially comparable to the OPC units. However, units are in lb/hr and not given in a concentration. The other site (Washington County Power) has a VOC limit of 5 ppmvd @15% O_2.

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, **OPC proposes a BACT limit for VOC as methane of 5.0 ppmvd at 15% O_2, excluding periods of startup and shutdown,** with compliance demonstrated via stack testing.[173]

5.10 Combustion Turbines GHG Assessment

This section contains a high-level review of pollutant formation and possible control technologies for the four modified 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 (i.e., for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[174] CH_4 can be emitted when natural gas and fuel oil are not burned completely in combustion.[175] 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.[176]

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) 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).

5.10.1 Turbine Systems CO_2 BACT

The following section presents BACT evaluations for CO_2 emissions from the modified turbine systems.

5.10.1.1 Identification of Potential CO_2 Control Technologies (Step 1)

OPC 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

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[173] 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.

[174] *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

[175] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998. Chapter 1, Section 3, *Fuel Oil Combustion*. July 1998.

[176] *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

technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are summarized in Appendix E, 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 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 redefine the source.

OPC 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. OPC excluded options such as battery storage, solar power generation, and hydrogen generation / combustion from the GHG control technology assessment as they would redefine the source: OPC proposes that the Talbot Energy Facility be 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 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.[177] Other more recent legal decisions have denied similar petitions for review. [178] Since this project involves modification of existing stationary combustion turbine units to allow use of a backup fuel, and not additional greenfield energy generation sources for power generation, consideration of alternative power generation methodologies, such as hydrogen generation / combustion, is also less feasible.

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 would redefine the source and therefore were not within the scope of the project. Additionally, natural gas (which has the lowest GHG emissions of any fossil fuel) is the primary fuel that will be utilized by the turbines.

5.10.1.1.1 Carbon Capture and Storage

CCS, also known as CO_2 sequestration, involves the cooling, separation and capture of CO_2 emissions from flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the

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[177] 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."

[178] Such as the Ocotillo Plant EAB decision in September 2016, regarding pairing of battery storage with proposed new turbines. In that instance, the EAB denied the petition for review.

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.[179] Since most storage locations for CO_2 are greater than 800 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.[180]

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.

5.10.1.1.2 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.

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.

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[179] 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

[180] *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, US Department of Energy. https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf

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.

5.10.1.2 Elimination of Technically Infeasible CO_2 Control Options – Turbine Systems (Step 2)

5.10.1.2.1 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-fired combined-cycle turbines.

Carbon Capture

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)[181] 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."[182]

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.[183] 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 the start of Phase 3 to develop a path to commercialization for a coal-fired utility.[184] Note that the economic feasibility of membrane-

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[181] *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

[182] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[183] Website reviewed January 2021: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[184] *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

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 Field, providing options for carbon storage as well as for enhanced oil recovery.[185] Review of the DoE's research projects do not indicate any activity related to fuel oil combustion sources.[186] 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 OPC's knowledge, the technology has never been commercially demonstrated for flue gas control in natural gas fired turbine operations.[187]

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.[188] 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, OPC 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.[189] 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

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[185] *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

[186] Website reviewed June 2023: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[187] 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.

[188] *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

[189] *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

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 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 most limiting factor is the availability of a mechanism for OPC to permanently store the captured CO_2.

NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[190] According to the database, the Paluxy Formation in Citronelle, Alabama is the closest sequestration site where CO_2 can be stored in the future. The Citronelle Project is a demonstration-scale Southeast Regional Carbon Sequestration Partnership (SECARB) CO_2 sequestration project site that achieved an injection of more than 114,000 metric tons of CO_2 with the potential to sequester additional CO_2.[191] The injection location is a saline reservoir within the Citronelle Oilfield in Mobile County, Alabama. Based on a review of the NETL database, Citronelle, Alabama the is the closest pilot or large-scale CO_2 sequestration project site to the Talbot Energy Facility and is approximately 232 miles from the Facility.

OPC has concluded that CCS technology is not technically feasible at this time, based on the discussions provided. Additionally, for the recently proposed rule, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units*, U.S. EPA concluded that the use of CCS was not the best system of emissions reduction (BSER) for simple-cycle combustion turbines:[192]

> *EPA is not proposing that CCS is the BSER for simple cycle combustion turbines based on the Agency's assessment that CCS may not be cost-effective for such combustion turbines when operated at intermediate load. This rationale applies with*

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[190] Carbon Capture and Storage Database maintained by the NETL, accessed May 2023 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[191] *Final Project Report – SECARB Phase III,* SECARB. Report at https://www.osti.gov/servlets/purl/1823250

[192] Supplementary Information for proposed rule, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units*, posted May 23, 2023.

https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0001 *even greater force for low load combustion turbines. In addition, currently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to do this is to use a HSRG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For these reasons, the Agency is not proposing that CCS qualifies as the BSER for this subcategory of sources.*

However, despite the significant technical challenges discussed earlier in implementing CCS technology on turbine systems of this size, OPC is including CCS in Step 3 of this analysis for the sake of discussion, despite having concluded that CCS is technically infeasible.

5.10.1.2.2 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.[193] However, usage of combined-cycle technology here would redefined the source and is not feasible for this project, as it will remove the turbine's capability to perform its function as a quick-starting unit used to meet peak grid demand. 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 and will not be evaluated beyond this step as it fundamentally changes the scope of the project. The EPA Environmental Appeals Board (EAB) affirmed the determination that simple-cycle and combined-cycle 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.[194]

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.

5.10.1.3 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.

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[193] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

[194] 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."*

- Carbon capture and storage (CCS), 90% reduction[195]
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices, reduction efficiency is not applicable.

5.10.1.4 Evaluation of Most Stringent CO_2 Control Technologies (Step 4)

5.10.1.4.1 Carbon Capture and Storage

As the most stringent control option available, CCS would be considered BACT, if feasible and barring the consideration of its energy, environmental, and/or economic impacts. However, as noted above, CCS is infeasible, and for the reasons outlined in this section, this option should not be relied upon as BACT due to cost-effectiveness considerations. Therefore, 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 Talbot Energy Facility site to the nearest carbon sequestration site. Currently, there exists no carbon storage sites in the state of Georgia, and the site closest to Talbot Energy Facility is the Citronelle Oilfield in Mobile County, Alabama. If the shortest possible pipeline between these sites were to be installed, 232 miles of pipeline would be installed, crossing from Georgia into Alabama.[196] In addition, at least one injection well will need to be installed at the site. Costs involved include an initial site screening, purchasing of injection equipment, well construction, permitting, 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 1,686 $/kW.[197] 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.

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[195] *Estimating Carbon Dioxide Transport and Storage Costs*, National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Page 9, March 2010.

[196] Distance from the Facility to the nearest potential CO_2 sequestration facility (Citronelle Oilfield) per the Southeast Regional Carbon Sequestration Partnership (SECARB), conservatively assuming the shortest distance as the pipeline route.

[197] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, October 2022, Exhibit 5-17, Case B31A Total Plant Cost Details (page 577) and Exhibit 5-31. Case B31B Total Plant Cost Details (page 595).

https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

When the aforementioned costs are summed, the total capital costs for installing a CCS system are greater than $750 million. 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 fixed operation and maintenance costs.[198]
- The actual storage of the gas at a chosen location requires, for example, permitting, pore space acquisition, daily expenses, consumables, surface maintenance, and subsurface maintenance.[199]

Based on the calculations completed for these costs, the total annualized cost for operation and maintenance of the CCS system will exceed $62 million. The resulting annualized total capital and operating cost per ton of CO_2 controlled is approximately $156 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.

5.10.1.5 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 E 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 and the nature of GHGs, 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 Talbot Energy Facility. To calculate the BACT limit, emission factors for fuel combustion were based on Appendix G to 40 CFR 75 for CO_2 and U.S. EPA default fuel combustion emission factors found in 40 CFR Part 98 Subpart C, Table C-2 for CH_4 and N_2O, converted from units of kg/MMBtu to lb/MMBtu.

As detailed in Appendix E, multiplying the 40 CFR 75 and U.S. EPA emission factors by the maximum annual operating capacity for each type of fuel yields maximum potential emissions of 263,239 tons of CO_2e/year from natural gas combustion and 50,014 tons of CO_2e/year from fuel oil combustion per modified turbine.

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[198] *Carbon Dioxide Transport and Storage Costs in NETL Studies,* March 2013 DOE/NETL-2013/1614, Exhibit 2.

[199] *Estimating Carbon Dioxide Transport and Storage Costs*, March 2010 National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

Summing these together yields potential CO_2e emissions of 313,253 tpy from each of the modified turbine systems. As such, OPC Talbot is proposing a BACT limit of **313,253 tpy** of CO_2e on a 12-month rolling averaging period for each modified turbine unit.

Based on a review of the RBLC database, the results of which are in Appendix E, BACT is established as a mass-based limit (on a CO_2e basis), taking into account "Energy efficient design and operations". The BACT limit being proposed is comparable to other limits that have been established for facilities with similar systems in place. As such, OPC believes the proposed BACT limit is appropriate to comply with PSD requirements.

Compliance with the proposed BACT limit will be demonstrated by monitoring fuel consumption for each fuel type. Specifically, the monthly CO_2e emissions will be calculated based on the monthly fuel use, the CO_2 emission factor based on Equation G-4 in Appendix G to 40 CFR 75, the CH_4 and N_2O emission factors from 40 CFR Part 98 Subpart C, Table and C-2, and the current GWPs from 40 CFR Part 98 Subpart A, Table A-1 (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, OPC 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).

5.10.2 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.

5.10.2.1 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 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.

5.10.2.2 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.

5.10.2.3 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.

5.10.2.4 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.

5.10.2.5 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. OPC 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 5.10.1.5. 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).

5.10.3 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.[200] 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.[201] Therefore, there is a tradeoff between NO_X and N_2O emissions when developing a combustion control strategy which influences the BACT selection process.

5.10.3.1 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.[202] 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.

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[200] Angello, L., Electric Power Research Institute, *Fuel Composition Impacts on Combustion Turbine Operability*, March 2006.

[201] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, February 2004.

[202] *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

5.10.3.2 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.[203] 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.

5.10.3.3 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.

5.10.3.4 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 OPC'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.[204]

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, OPC 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.

5.10.3.5 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. OPC 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 5.10.1.5. 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).

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[203] *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

[204] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

5.11 Fuel Oil Storage Tank VOC Assessment

OPC is proposing to construct and operate up to two new vertical fixed roof tanks which will store distillate fuel oil and each have a capacity of 1.58 million gallons. Annual emissions resulting from the storage tanks have been estimated in Appendix B and are not expected to exceed 0.94 tpy in total. Given the low magnitude of emissions from the proposed fuel oil storage tanks, OPC proposes that the tanks 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 tanks, 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 fuel oil storage tank. The use of floating roofs is also not considered effective for controlling VOC emissions from liquids having low vapor pressures such as fuel oil.[205] 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, OPC is proposing to incorporate the use of submerged fill systems in the fuel oil storage tanks 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 OPC will utilize to control emissions from the fuel oil storage tanks 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 reduce evaporative losses. Solar radiation will increase the temperature of the liquid in a storage tank, but the extent of the temperature increase is informed 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). Light colored paint is reflective and typically used to minimize the tank's ambient temperature, which, in turn, reduces standing losses.[206]

OPC has determined that BACT for the proposed fuel oil storage tanks will be the use of good operating and 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.

5.12 Fire Pump NO_X Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for NO_X emissions from the emergency diesel-fired fire pump engine.

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205 *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.

206 Eric Stricklin. "Evaporative Losses From Storage Tanks," Chesapeake Operating, Inc. http://technokontrol.com/pdf/evaporation/evaporation-loss-measurement.pdf.

5.12.1 NO_X Formation – Fire Pump

The pathways of NO_X formation are discussed in Section 5.6.1. NO_X from the combustion of diesel (distillate fuel oil) primarily occurs due to either thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X), or the conversion of chemically bound nitrogen in the fuel (fuel NO_X).[207] The size of the fire pump engine proposed for installation at the Facility (455 hp) could be a limiting factor in the technology and emissions performance data applicable in the control technology and emission limit selection process.

5.12.2 Identification of NO_X Control Technologies – Fire Pump (Step 1)

Using the RBLC resource, as well as a review of technical literature, potentially applicable NO_X control technologies for fire pump engines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:

- Purchase of certified NSPS Subpart IIII engine;
- Good combustion practices; and
- Limitations on hours of operation

Post-combustion control options include:

- SCR

5.12.3 Elimination of Technically Infeasible NO_X Control Options – Fire Pump (Step 2)

All of the potential control technologies discussed in Step 1 are conservatively presumed to be technically feasible.

5.12.4 Summary and Ranking of Remaining NO_X Controls – Fire Pump (Step 3)

The remaining control methods are listed below, in descending order of the expected NO_X reductions.

- SCR, 90% reduction[208]
- Purchase of certified NSPS Subpart IIII engine; good combustion practices; and limitations on hours of operation, reduction efficiency is not applicable.

5.12.5 Evaluation of Most Stringent NO_X Controls – Fire Pump (Step 4)

As shown in Step 3, SCR is the highest ranking potentially feasible control technology for the emergency diesel-fired fire pump engine. However due to the low NO_X emissions (0.77 tpy) from the fire pump engine and the restriction to 500 hours per year of operation, post combustion controls such as an SCR are not cost effective. 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.

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[207] AP-42, Chapter 1, Section 3, *Fuel Oil Combustion*, May 2010

[208] https://www.epa.gov/sites/default/files/2020-08/documents/fscr.pdf

5.12.6 Selection of Emission Limits and Controls for NO_X BACT – Fire Pump (Step 5)

Good combustion practices and limiting the operating hours for the fire pump engine is proposed as BACT. Proposed BACT limits will be set to the emission limits required by NSPS Subpart IIII, for which compliance is demonstrated through proper operation and maintenance of an EPA certified engine. Therefore, the BACT limit for the fire pump is **4.0 g/kW-hr (3.0 lb/hp-hr)** in terms of NMHC + NO_X, per Table 4 of NSPS Subpart IIII.[209]

5.13 Fire Pump Filterable PM and Total PM_{10}/$PM_{2.5}$ Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for filterable PM, total PM_{10}, and total $PM_{2.5}$ emissions from the emergency diesel-fired fire pump engine.

5.13.1 PM Formation – Fire Pump

The primary causes of PM formation are discussed in Section 5.7.1. PM from the combustion of diesel (distillate fuel oil) mainly occurs due to incomplete combustion and by ash and sulfur in the fuel. For distillate oil firing specifically (with low ash and sulfur in fuel), PM emissions are typically carbonaceous particles resulting from incomplete combustion of oil.[210] The size of the fire pump engine proposed for installation at the Facility (455 hp) could be a limiting factor in the technology and emissions performance data applicable in the control technology and emission limit selection process.

5.13.2 Identification of PM Control Technologies – Fire Pump (Step 1)

Using the RBLC resource, as well as a review of technical literature, potentially applicable PM control technologies for fire pump engines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:

- Purchase of certified NSPS Subpart IIII engine;
- Good combustion practices;
- Clean fuel; and
- Limitations on hours of operation

Post-combustion control options include:

- Catalyzed diesel particulate filters (CDPF) for diesel-driven engines; and
- Diesel Oxidation Catalysts (DOC)

5.13.3 Elimination of Technically Infeasible PM Control Options – Fire Pump (Step 2)

All of the potential control technologies discussed in Step 1 are conservatively presumed to be technically feasible.

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209 Non-methane hydrocarbons (NMHC).

210 AP-42, Chapter 1, Section 3, *Fuel Oil Combustion*, May 2010

5.13.4 Summary and Ranking of Remaining PM Controls – Fire Pump (Step 3)

The remaining control methods are listed below, in descending order of the expected PM reductions.

- CDPF, 90% reduction[211]
- DOC, 40% reduction[212]
- Purchase of certified NSPS Subpart IIII engine; good combustion practices; clean fuel; and limitations on hours of operation, reduction efficiency is not applicable.

5.13.5 Evaluation of Most Stringent PM Controls – Fire Pump (Step 4)

As shown in Step 3, CDPF is the highest ranking potentially feasible control technology for the emergency diesel-fired fire pump engine. However due to the low PM emissions (0.016 tpy) from the fire pump engine and the restriction to 500 hours per year of operation, post combustion controls such as a CDPF and/or DOC are not cost effective. Given the capital costs involved with installation of add-on controls for reduction of significantly 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.

5.13.6 Selection of Emission Limits and Controls for PM BACT – Fire Pump (Step 5)

Good combustion practices, clean fuel (with the use of ULSD), and limiting the operating hours for the fire pump engine is proposed as BACT. Proposed BACT limits will be set to the emission limits required by NSPS Subpart IIII, for which compliance is demonstrated through proper operation and maintenance of an EPA certified engine. Therefore, the BACT limit for the fire pump is **0.54 g/kW-hr (0.40 lb/hp-hr)**, per Table 4 of NSPS Subpart IIII.

5.14 Fire Pump CO Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for CO emissions from the emergency diesel-fired fire pump engine.

5.14.1 CO Formation – Fire Pump

The primary causes of CO formation are discussed in Section 5.8.1. CO from the combustion of diesel (distillate fuel oil) mainly occurs due to incomplete combustion.[213] The size of the fire pump engine proposed for installation at the Facility (455 hp) could be a limiting factor in the technology and emissions performance data applicable in the control technology and emission limit selection process.

5.14.2 Identification of CO Control Technologies – Fire Pump (Step 1)

Using the RBLC resource, as well as a review of technical literature, potentially applicable CO control technologies for fire pump engines were identified based on the principles of control technology and engineering experience for general combustion units.

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[211] https://www.epa.gov/sites/default/files/2016-03/documents/420f10029.pdf

[212] https://www.epa.gov/sites/default/files/2016-03/documents/420f10031.pdf

[213] AP-42, Chapter 1, Section 3, *Fuel Oil Combustion*, May 2010

Combustion control options include:

- Purchase of certified NSPS Subpart IIII engine;
- Good combustion practices; and
- Limitations on hours of operation

Post-combustion control options include:

- DOC; and
- CDPF

5.14.3 Elimination of Technically Infeasible CO Control Options – Fire Pump (Step 2)

All of the potential control technologies discussed in Step 1 are conservatively presumed to be technically feasible.

5.14.4 Summary and Ranking of Remaining CO Controls – Fire Pump (Step 3)

The remaining control methods are listed below, in descending order of the expected CO reductions.

- CDPF, 90% reduction[214]
- DOC, 60% reduction[215]
- Purchase of certified NSPS Subpart IIII engine; good combustion practices; clean fuel; and limitations on hours of operation, reduction efficiency is not applicable.

5.14.5 Evaluation of Most Stringent CO Controls – Fire Pump (Step 4)

As shown in Step 3, CDPF is the highest ranking potentially feasible control technology for the emergency diesel-fired fire pump engine. However due to the low CO emissions (0.46 tpy) from the fire pump engine and the restriction to 500 hours per year of operation, post combustion controls such as a CDPF and/or DOC are not cost effective. 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.

5.14.6 Selection of Emission Limits and Controls for CO BACT – Fire Pump (Step 5)

Good combustion practices and limiting the operating hours for the fire pump engine is proposed as BACT. Proposed BACT limits will be set to the emission limits required by NSPS Subpart IIII, for which compliance is demonstrated through proper operation and maintenance of an EPA certified engine. Therefore, the BACT limit for the fire pump is **11.4 g/kW-hr (8.5 lb/hp-hr)**, per Table 4 of NSPS Subpart IIII.

5.15 Fire Pump VOC Assessment

The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits for proposed BACT for VOC emissions from the emergency diesel-fired fire pump engine.

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214 https://www.epa.gov/sites/default/files/2016-03/documents/420f10029.pdf

215 https://www.epa.gov/sites/default/files/2016-03/documents/420f10031.pdf

5.15.1 VOC Formation – Fire Pump

The primary causes of VOC formation are discussed in Section 5.9.1. VOC from the combustion of diesel (distillate fuel oil) mainly occurs due to incomplete combustion resulting in the emissions of unburned vapor phase hydrocarbons.[216] The size of the fire pump engine proposed for installation at the Facility (455 hp) could be a limiting factor in the technology and emissions performance data applicable in the control technology and emission limit selection process.

5.15.2 Identification of VOC Control Technologies – Fire Pump (Step 1)

Using the RBLC search, as well as a review of technical literature, potentially applicable VOC control technologies for fire pump engines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:

- Purchase of certified NSPS Subpart IIII engine;
- Good combustion practices; and
- Limitations on hours of operation

Post-combustion control options include:

- DOC; and
- CDPF

5.15.3 Elimination of Technically Infeasible VOC Control Options – Fire Pump (Step 2)

All of the potential control technologies discussed in Step 1 are conservatively presumed to be technically feasible.

5.15.4 Summary and Ranking of Remaining VOC Controls – Fire Pump (Step 3)

The remaining control methods are listed below, in descending order of the expected VOC reductions.

- CDPF, 90% reduction[217]
- DOC, 75% reduction[218]
- Purchase of certified NSPS Subpart IIII engine; good combustion practices; clean fuel; and limitations on hours of operation, reduction efficiency is not applicable.

5.15.5 Evaluation of Most Stringent VOC Controls – Fire Pump (Step 4)

As shown in Step 3, CDPF is the highest ranking potentially feasible control technology for the emergency diesel-fired fire pump engine. However due to the low VOC emissions (0.028 tpy) from the fire pump engine and the restriction to 500 hours per year of operation, post combustion controls such as a CDPF and/or DOC are not cost effective. Given the capital costs involved with installation of add-on controls for reduction of

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216 AP-42, Chapter 1, Section 3, *Fuel Oil Combustion*, May 2010

217 https://www.epa.gov/sites/default/files/2016-03/documents/420f10029.pdf

218 https://www.epa.gov/sites/default/files/2016-03/documents/420f10031.pdf

significantly 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.

5.15.6 Selection of Emission Limits and Controls for VOC BACT – Fire Pump (Step 5)

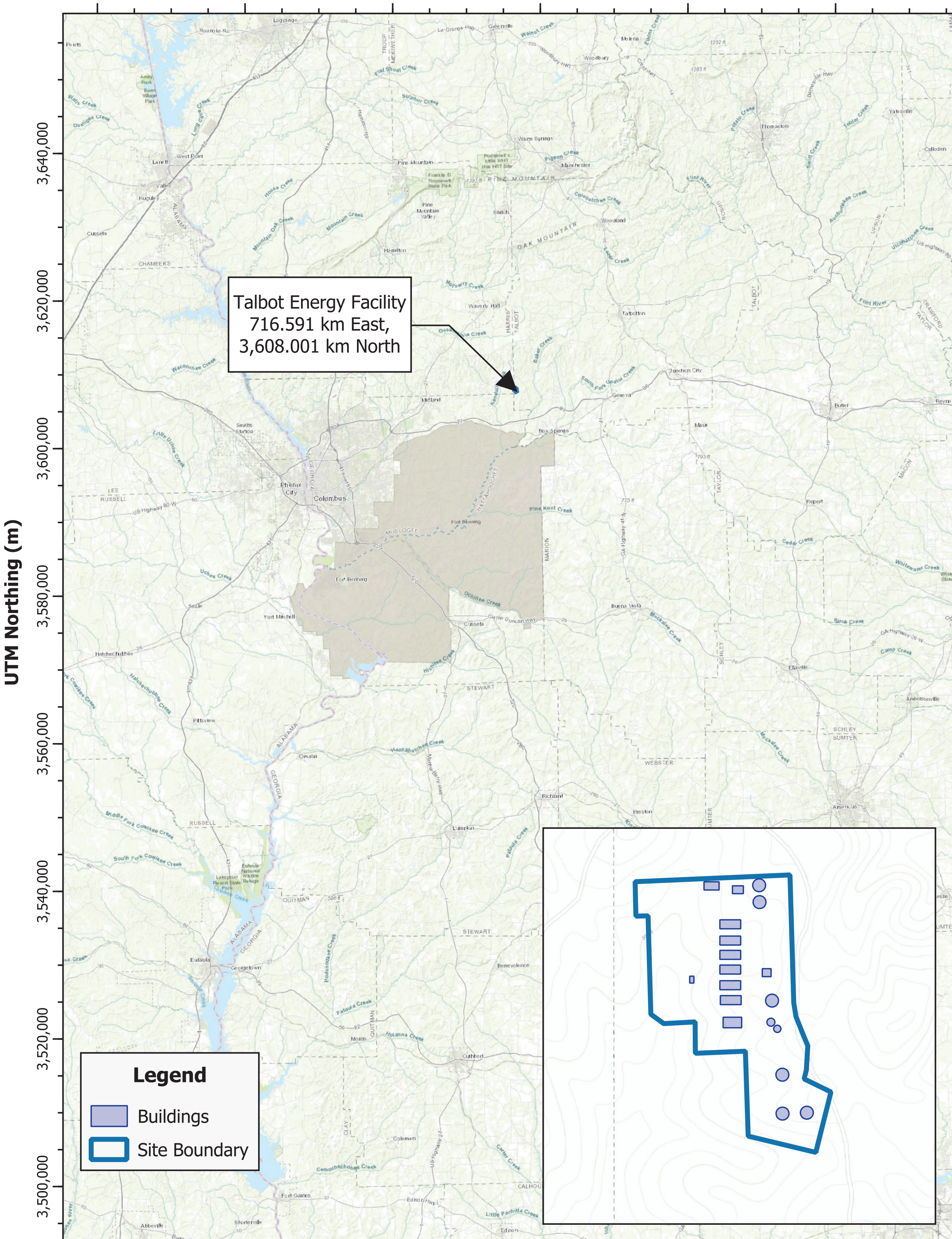
Good combustion practices and limiting the operating hours for the fire pump engine is proposed as BACT. Proposed BACT limits will be set to the emission limits required by NSPS Subpart IIII, for which compliance is demonstrated through proper operation and maintenance of an EPA certified engine. Therefore, the BACT limit for the fire pump is **4.0 g/kW-hr (3.0 lb/hp-hr)** in terms of NMHC + NO_X, per Table 4 of NSPS Subpart IIII.

5.16 Fire Pump GHG Assessment

GHG emissions from the emergency diesel-fired fire pump engine result from the oxidation of fuel carbon. This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process as there are no post-combustion control technologies identified or available for GHG emissions from small emergency engines. The proposed BACT for GHG emissions from the emergency engines is to follow good combustion practices, the use of ULSD, limiting hours of operation and proper operation and maintenance consistent with NSPS Subpart IIII.

APPENDIX A. AREA MAP

Figure A-1. Area Site Map



UTM Easting (m)

All coordinates shown in UTM Coordinates,
UTM Zone 16, NAD 83 Datum

APPENDIX B. NSR EVALUATION

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.)
Mar-14	21,452	19,362	21,993	17,511
Apr-14	7,358	8,498	8,952	6,245
May-14	18,935	74,330	32,178	51,097
Jun-14	10,425	78,157	55,636	70,422
Jul-14	23,275	123,602	116,930	100,497
Aug-14	21,447	164,573	114,413	123,300
Sep-14	4,434	88,340	34,968	46,199
Oct-14	25,285	123,073	111,736	109,343
Nov-14	2,236	18,531	26,233	35,875
Dec-14	--	5,919	5,604	3,046
Jan-15	--	15,181	--	--
Feb-15	--	--	2,211	--
Mar-15	--	2,392	--	--
Apr-15	1,350	35,655	32,216	--
May-15	58,965	194,116	152,637	127,146
Jun-15	71,838	151,653	112,455	126,051
Jul-15	160,282	254,219	78,819	245,925
Aug-15	88,583	204,997	58,900	205,461
Sep-15	84,410	168,342	44,945	160,210
Oct-15	103,654	193,796	8,030	31,988
Nov-15	35,401	86,057	11,057	56,865
Dec-15	--	--	--	--
Jan-16	4,276	--	2,269	2,212
Feb-16	3,721	--	15,926	20,014
Mar-16	93,257	--	108,459	122,369
Apr-16	104,868	151,532	107,911	90,152
May-16	184,740	340,405	310,419	289,669
Jun-16	218,467	313,505	299,367	301,551
Jul-16	258,940	228,066	327,640	328,739
Aug-16	258,168	243,081	329,200	307,897
Sep-16	149,969	147,992	245,711	241,407
Oct-16	--	--	12,844	8,287
Nov-16	12,536	8,410	23,752	17,215
Dec-16	30,737	19,758	55,863	50,204
Jan-17	5,886	16,112	--	44,207
Feb-17	--	--	--	3,258
Mar-17	3,626	8,056	--	21,197
Apr-17	22,973	23,398	60,050	147,651
May-17	103,736	98,030	81,681	203,617
Jun-17	56,743	41,304	33,930	118,763
Jul-17	175,590	163,297	147,135	254,835
Aug-17	140,423	121,501	126,533	198,411
Sep-17	89,017	74,034	79,218	144,069
Oct-17	33,842	4,677	4,409	85,991
Nov-17	28,554	34,994	14,231	34,034
Dec-17	1,812	--	3,306	--

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-18	49,763	25,562	24,057	--
Feb-18	--	--	--	--
Mar-18	4,487	--	--	--
Apr-18	8,310	4,368	2,254	5,140
May-18	147,284	122,303	107,267	240,432
Jun-18	182,821	170,043	154,149	137,970
Jul-18	226,533	214,350	199,153	180,288
Aug-18	229,492	214,392	207,429	196,239
Sep-18	285,510	285,631	263,471	253,733
Oct-18	28,536	15,490	10,340	54,334
Nov-18	10,902	40	--	10,490
Dec-18	27,742	7,944	9,900	30,086
Jan-19	12,402	23,743	18,856	27,256
Feb-19	10,404	11,793	3,948	7,021
Mar-19	8,887	5,566	26,885	45,879
Apr-19	43,087	26,359	54,305	65,337
May-19	174,462	158,389	140,825	103,313
Jun-19	66,533	91,717	94,554	119,171
Jul-19	201,454	223,205	203,683	209,748
Aug-19	249,525	246,979	248,463	234,018
Sep-19	226,918	224,701	215,504	213,265
Oct-19	45,642	39,001	47,106	53,034
Nov-19	22,529	21,453	--	18,630
Dec-19	19,253	19,296	23,424	24,599
Jan-20	8,132	--	--	--
Feb-20	--	--	76	73
Mar-20	10,064	--	3,033	2,780
Apr-20	15,801	14,779	11,108	7,766
May-20	113,525	106,200	97,096	88,024
Jun-20	143,682	172,842	180,138	187,659
Jul-20	252,950	239,670	230,613	263,266
Aug-20	233,841	249,457	246,718	182,341
Sep-20	90,769	97,702	99,301	123,847
Oct-20	37	35	50,622	87,878
Nov-20	--	--	47,646	20,646
Dec-20	7,198	8,693	--	--
Jan-21	2,753	1,273	39	42
Feb-21	--	3,691	1,247	--
Mar-21	25,349	13,496	12,288	--
Apr-21	37,909	46,404	45,136	63,735
May-21	77,055	79,872	83,192	80,040
Jun-21	149,509	143,658	134,000	124,267
Jul-21	109,507	114,289	108,321	111,980
Aug-21	103,992	113,053	103,061	100,067
Sep-21	32,565	39,981	20,538	40,459
Oct-21	1,079	1,133	86,268	96,350
Nov-21	8,324	5,812	3,440	--
Dec-21	--	--	--	--

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-22	--	--	--	--
Feb-22	--	--	40	38
Mar-22	--	--	--	--
Apr-22	3,701	--	19,327	5,723
May-22	133,694	110,427	109,341	84,482
Jun-22	243,320	236,095	262,429	226,159
Jul-22	348,657	322,808	357,168	325,965
Aug-22	306,070	310,980	308,974	299,807
Sep-22	196,416	184,303	190,019	167,598
Oct-22	1,678	--	13,045	12,240
Nov-22	--	12,314	20,392	12,567
Dec-22	--	25,752	49,240	50,213

1. Heat inputs represent historically measured site data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system.

Table B-2. Historically Monitored/Reported Emissions[1,2]

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 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)
Mar-14	0.55	6.0E-03	0.30	1,275	0.43	6.0E-03	2.80	1,151	0.70	7.0E-03	5.60	1,307	0.44	5.0E-03	3.30	1,041
Apr-14	0.13	2.0E-03	--	437	0.18	3.0E-03	0.90	505	0.17	3.0E-03	0.50	532	0.13	2.0E-03	0.30	371
May-14	0.25	6.0E-03	0.30	1,125	1.05	2.2E-02	1.90	4,418	0.59	1.0E-02	1.00	1,912	0.80	1.5E-02	1.70	3,037
Jun-14	0.14	3.0E-03	--	620	1.04	2.3E-02	1.90	4,645	0.73	1.7E-02	1.20	3,306	0.99	2.1E-02	1.40	4,185
Jul-14	0.27	7.0E-03	--	1,383	1.52	3.7E-02	2.10	7,346	1.47	3.5E-02	2.40	6,949	1.37	3.0E-02	1.90	5,972
Aug-14	0.29	6.0E-03	--	1,275	2.31	4.9E-02	2.70	9,781	1.50	3.4E-02	2.20	6,800	1.77	3.7E-02	2.50	7,328
Sep-14	7.0E-02	1.0E-03	--	264	1.22	2.7E-02	1.80	5,250	0.43	1.0E-02	0.80	2,078	0.70	1.4E-02	1.30	2,746
Oct-14	0.34	8.0E-03	0.10	1,503	1.76	3.7E-02	1.80	7,314	1.34	3.4E-02	1.10	6,641	1.62	3.3E-02	1.90	6,498
Nov-14	3.9E-02	1.0E-03	--	133	0.41	6.0E-03	0.90	1,101	0.56	8.0E-03	0.80	1,559	0.79	1.1E-02	1.20	2,132
Dec-14	--	--	--	--	0.15	2.0E-03	0.20	352	0.11	2.0E-03	0.50	333	7.2E-02	1.0E-03	0.10	181
Jan-15	--	--	--	--	0.44	5.0E-03	0.80	902	--	--	--	--	--	--	--	--
Feb-15	--	--	--	--	--	--	--	--	7.1E-02	1.0E-03	0.80	131	--	--	--	--
Mar-15	--	--	--	--	6.0E-02	1.0E-03	0.20	142	--	--	--	--	--	--	--	--
Apr-15	4.9E-02	--	--	80	0.54	1.1E-02	0.40	2,119	0.43	1.0E-02	0.40	1,914	--	--	--	--
May-15	0.97	1.8E-02	0.30	3,504	2.87	5.8E-02	3.00	11,536	2.10	4.6E-02	3.20	9,071	1.89	3.8E-02	2.20	7,557
Jun-15	0.99	2.2E-02	0.80	4,269	2.28	4.6E-02	2.50	9,013	1.54	3.4E-02	2.30	6,683	1.69	3.8E-02	2.00	7,491
Jul-15	2.05	4.8E-02	2.70	9,526	3.72	7.6E-02	3.50	15,108	1.15	2.4E-02	2.50	4,684	3.12	7.4E-02	3.00	14,615
Aug-15	1.22	2.7E-02	2.30	5,264	2.93	6.2E-02	3.30	12,183	0.91	1.8E-02	1.30	3,500	2.78	6.2E-02	3.00	12,210
Sep-15	1.17	2.5E-02	0.80	5,017	2.48	5.1E-02	2.10	10,005	0.72	1.3E-02	1.60	2,671	2.18	4.8E-02	2.20	9,521
Oct-15	1.65	3.1E-02	0.50	6,160	3.23	5.8E-02	2.30	11,517	0.17	2.0E-03	1.00	477	0.52	1.0E-02	0.70	1,901
Nov-15	0.50	1.1E-02	0.10	2,104	1.29	2.6E-02	1.00	5,114	0.16	3.0E-03	0.10	657	0.74	1.7E-02	0.70	3,380
Dec-15	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Jan-16	9.5E-02	1.0E-03	--	254	--	--	--	--	7.7E-02	1.0E-03	0.20	135	6.3E-02	1.0E-03	0.10	131
Feb-16	7.4E-02	1.0E-03	--	221	--	--	--	--	0.32	5.0E-03	0.60	947	0.42	6.0E-03	0.80	1,189
Mar-16	1.63	2.8E-02	0.40	5,542	--	--	--	--	1.83	3.3E-02	1.70	6,445	2.00	3.7E-02	1.80	7,272
Apr-16	1.75	3.1E-02	1.20	6,233	2.70	4.5E-02	1.70	9,005	1.60	3.2E-02	1.40	6,413	1.41	2.7E-02	1.20	5,358
May-16	2.90	5.5E-02	1.70	10,979	5.77	0.10	3.90	20,229	4.67	9.3E-02	4.30	18,448	4.40	8.7E-02	4.10	17,216
Jun-16	3.01	6.6E-02	2.00	12,983	4.61	9.4E-02	3.40	18,630	4.14	9.0E-02	4.50	17,791	4.29	9.0E-02	3.70	17,921
Jul-16	3.50	7.8E-02	3.60	15,389	3.05	6.8E-02	3.10	13,554	4.38	9.8E-02	4.20	19,471	4.36	9.9E-02	4.00	19,536
Aug-16	3.36	7.7E-02	3.60	15,341	3.32	7.3E-02	3.40	14,446	4.48	9.9E-02	3.90	19,563	3.99	9.2E-02	3.40	18,298
Sep-16	2.18	4.5E-02	2.30	8,912	2.21	4.4E-02	2.60	8,795	3.60	7.4E-02	3.50	14,602	3.46	7.2E-02	3.30	14,347
Oct-16	--	--	--	--	--	--	--	--	0.20	4.0E-03	0.20	763	0.14	2.0E-03	0.10	493
Nov-16	0.30	4.0E-03	0.50	745	0.16	3.0E-03	0.20	500	0.46	7.0E-03	0.70	1,411	0.39	5.0E-03	0.40	1,023
Dec-16	0.64	9.0E-03	1.00	1,827	0.41	6.0E-03	0.90	1,174	1.17	1.7E-02	1.20	3,320	1.03	1.5E-02	1.00	2,983

Table B-2. Historically Monitored/Reported Emissions[1,2]

	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 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)
Jan-17	0.14	2.0E-03	0.30	350	0.31	5.0E-03	0.50	957	--	--	--	--	0.86	1.3E-02	0.90	2,627
Feb-17	--	--	--	--	--	--	--	--	--	--	--	--	7.6E-02	1.0E-03	0.10	194
Mar-17	8.9E-02	1.0E-03	0.20	216	0.17	2.0E-03	0.20	479	--	--	--	--	0.42	6.0E-03	0.30	1,260
Apr-17	0.42	7.0E-03	0.50	1,365	0.47	7.0E-03	0.30	1,391	1.15	1.8E-02	1.30	3,569	2.16	4.4E-02	1.90	8,775
May-17	1.64	3.1E-02	1.90	6,165	1.50	2.9E-02	1.70	5,826	1.27	2.5E-02	1.40	4,854	3.25	6.1E-02	2.30	12,101
Jun-17	0.84	1.7E-02	0.80	3,372	0.63	1.2E-02	0.70	2,455	0.52	1.0E-02	0.60	2,016	1.56	3.6E-02	1.80	7,058
Jul-17	2.51	5.3E-02	2.90	10,435	2.40	4.9E-02	3.10	9,704	2.26	4.4E-02	2.60	8,744	3.33	7.6E-02	3.10	15,144
Aug-17	2.05	4.2E-02	2.80	8,345	1.87	3.6E-02	2.50	7,221	1.80	3.8E-02	2.20	7,520	2.81	6.0E-02	3.70	11,792
Sep-17	1.39	2.7E-02	1.70	5,290	1.14	2.2E-02	1.80	4,400	1.15	2.4E-02	1.00	4,708	2.09	4.3E-02	2.10	8,562
Oct-17	0.65	1.0E-02	0.80	2,011	7.8E-02	1.0E-03	0.10	278	7.3E-02	1.0E-03	0.10	262	1.44	2.6E-02	2.50	5,110
Nov-17	0.59	9.0E-03	0.80	1,697	0.60	1.0E-02	0.80	2,080	0.24	4.0E-03	0.30	846	0.54	1.0E-02	0.60	2,023
Dec-17	5.3E-02	1.0E-03	0.20	108	--	--	--	--	7.0E-02	1.0E-03	0.20	196	--	--	--	--
Jan-18	0.95	1.5E-02	1.00	2,957	0.52	8.0E-03	0.80	1,519	0.58	7.0E-03	0.70	1,430	--	--	--	--
Feb-18	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Mar-18	0.10	1.0E-03	0.10	267	--	--	--	--	--	--	--	--	--	--	--	--
Apr-18	0.15	2.0E-03	0.20	494	8.1E-02	1.0E-03	0.20	260	7.1E-02	1.0E-03	0.10	134	0.12	2.0E-03	0.50	305
May-18	2.37	4.4E-02	2.50	8,753	1.79	3.7E-02	1.90	7,269	1.88	3.2E-02	1.80	6,374	3.84	7.2E-02	3.80	14,289
Jun-18	2.78	5.5E-02	3.60	10,865	2.30	5.1E-02	2.80	10,105	2.24	4.6E-02	2.90	9,161	2.31	4.1E-02	3.40	8,199
Jul-18	3.19	6.8E-02	3.40	13,463	2.81	6.4E-02	3.30	12,738	2.85	6.0E-02	2.50	11,836	2.72	5.4E-02	2.90	10,714
Aug-18	3.18	6.9E-02	3.10	13,638	2.98	6.4E-02	3.00	12,741	2.90	6.2E-02	3.20	12,327	3.10	5.9E-02	3.30	11,662
Sep-18	3.98	8.6E-02	3.10	16,968	3.96	8.6E-02	3.50	16,975	3.86	7.9E-02	3.40	15,657	3.99	7.6E-02	3.90	15,079
Oct-18	0.44	9.0E-03	0.60	1,696	0.24	5.0E-03	0.30	921	0.19	3.0E-03	0.40	615	0.89	1.6E-02	1.00	3,229
Nov-18	0.28	3.0E-03	0.60	648	1.0E-03	--	0.10	2.35	--	--	--	--	0.26	3.0E-03	0.50	623
Dec-18	0.57	8.0E-03	0.90	1,649	0.25	2.0E-03	0.60	472	0.48	3.0E-03	0.70	588	0.65	9.0E-03	1.20	1,788
Jan-19	0.22	4.0E-03	0.10	737	0.48	7.0E-03	0.60	1,411	0.44	6.0E-03	0.60	1,121	0.69	8.0E-03	1.00	1,620
Feb-19	0.19	3.0E-03	0.20	618	0.23	4.0E-03	0.30	701	8.4E-02	1.0E-03	0.30	235	0.15	2.0E-03	0.50	417
Mar-19	0.22	3.0E-03	0.60	528	0.13	2.0E-03	0.20	331	0.58	8.0E-03	1.00	1,598	0.99	1.4E-02	1.20	2,726
Apr-19	0.67	1.3E-02	0.60	2,560	0.39	8.0E-03	0.40	1,566	0.88	1.6E-02	0.80	3,228	1.07	2.0E-02	1.10	3,883
May-19	2.62	5.2E-02	2.70	10,368	2.38	4.8E-02	3.10	9,412	2.13	4.2E-02	2.70	8,369	1.62	3.1E-02	1.60	6,140
Jun-19	1.02	2.0E-02	1.50	3,954	1.34	2.8E-02	2.00	5,451	1.41	2.8E-02	1.50	5,619	1.83	3.6E-02	2.00	7,082
Jul-19	3.02	6.0E-02	3.10	11,972	3.14	6.7E-02	3.40	13,265	2.82	6.1E-02	2.80	12,105	2.97	6.3E-02	3.10	12,464
Aug-19	3.58	7.5E-02	2.90	14,829	3.36	7.4E-02	2.90	14,678	3.37	7.5E-02	3.30	14,765	3.36	7.0E-02	3.40	13,908
Sep-19	3.46	6.8E-02	3.10	13,486	3.14	6.7E-02	2.60	13,354	3.17	6.5E-02	3.00	12,807	3.52	6.4E-02	2.50	12,674
Oct-19	0.70	1.4E-02	0.70	2,712	0.52	1.2E-02	0.40	2,318	0.78	1.4E-02	2.60	2,800	1.04	1.6E-02	2.70	3,152
Nov-19	0.49	7.0E-03	1.80	1,339	0.52	6.0E-03	2.30	1,275	--	--	--	--	0.40	6.0E-03	0.50	1,107
Dec-19	0.41	6.0E-03	0.80	1,144	0.40	6.0E-03	0.70	1,147	0.56	7.0E-03	0.90	1,392	0.62	7.0E-03	1.30	1,462

Table B-2. Historically Monitored/Reported Emissions[1,2]

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 (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)	NO_X (tons/mo.)	SO_2 (tons/mo.)	CO (tons/mo.)	CO_2 (tons/mo.)
Jan-20	0.11	2.0E-03	0.10	483	--	--	--	--	--	--	--	--	--	--	--	--
Feb-20	--	--	--	--	--	--	--	--	4.0E-03	--	0.10	4.50	3.0E-03	--	0.10	4.30
Mar-20	0.21	3.0E-03	0.30	598	--	--	--	--	6.6E-02	1.0E-03	0.10	180	8.1E-02	1.0E-03	0.40	165
Apr-20	0.25	5.0E-03	0.20	939	0.22	4.0E-03	0.20	878	0.17	3.0E-03	0.10	660	0.15	2.0E-03	0.10	462
May-20	1.69	3.4E-02	1.80	6,747	1.50	3.2E-02	1.90	6,312	1.42	2.9E-02	1.40	5,770	1.37	2.6E-02	1.20	5,231
Jun-20	2.09	4.3E-02	3.10	8,539	2.33	5.2E-02	3.40	10,272	2.58	5.4E-02	2.60	10,705	2.92	5.6E-02	2.60	11,152
Jul-20	3.42	7.6E-02	4.00	15,033	3.00	7.2E-02	2.80	14,243	3.29	6.9E-02	2.60	13,705	3.78	7.9E-02	2.80	15,646
Aug-20	3.14	7.0E-02	2.60	13,896	3.20	7.5E-02	2.70	14,825	3.60	7.4E-02	2.30	14,663	2.68	5.5E-02	2.20	10,836
Sep-20	1.26	2.7E-02	1.40	5,394	1.31	2.9E-02	1.20	5,807	1.45	3.0E-02	0.90	5,902	1.86	3.7E-02	1.40	7,360
Oct-20	2.0E-03	--	0.10	2.21	1.0E-03	--	0.10	2.09	0.78	1.5E-02	0.50	3,008	1.36	2.6E-02	1.10	5,222
Nov-20	--	--	--	--	--	--	--	--	0.83	1.4E-02	0.70	2,831	0.44	6.0E-03	1.00	1,227
Dec-20	0.18	2.0E-03	0.50	428	0.19	3.0E-03	0.40	517	--	--	--	--	--	--	--	--
Jan-21	0.11	1.0E-03	0.60	164	3.6E-02	--	0.10	76	2.0E-03	--	0.10	2.32	2.0E-03	--	0.10	2.51
Feb-21	--	--	--	--	6.8E-02	1.0E-03	0.10	219	7.6E-02	--	0.20	74	--	--	--	--
Mar-21	0.65	8.0E-03	1.70	1,506	0.31	4.0E-03	0.90	802	0.30	4.0E-03	0.60	730	--	--	--	--
Apr-21	0.62	1.1E-02	0.70	2,253	0.69	1.4E-02	0.60	2,758	0.77	1.4E-02	0.70	2,682	1.12	1.9E-02	1.40	3,788
May-21	1.17	2.3E-02	1.10	4,579	1.14	2.4E-02	0.90	4,746	1.27	2.5E-02	1.10	4,944	1.44	2.4E-02	1.10	4,756
Jun-21	2.08	4.5E-02	1.80	8,885	2.02	4.3E-02	1.50	8,537	1.91	4.0E-02	1.30	7,963	2.06	3.7E-02	2.20	7,385
Jul-21	1.49	3.3E-02	1.20	6,508	1.53	3.4E-02	2.20	6,792	1.45	3.2E-02	1.00	6,437	1.66	3.4E-02	1.30	6,655
Aug-21	1.61	3.1E-02	1.60	6,180	1.86	3.4E-02	1.60	6,718	1.59	3.1E-02	1.30	6,125	1.60	3.0E-02	1.90	5,947
Sep-21	0.52	1.0E-02	0.60	1,935	0.77	1.2E-02	0.70	2,376	0.35	6.0E-03	0.20	1,221	0.63	1.2E-02	0.50	2,404
Oct-21	3.7E-02	--	0.10	64	2.9E-02	--	--	67	1.37	2.6E-02	0.80	5,127	1.53	2.9E-02	1.20	5,726
Nov-21	0.27	2.0E-03	0.70	495	0.18	2.0E-03	0.30	345	8.0E-02	1.0E-03	0.10	204	--	--	--	--
Dec-21	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Feb-22	--	--	--	--	--	--	--	--	2.0E-03	--	0.10	2.38	1.0E-03	--	0.10	2.28
Mar-22	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Apr-22	6.6E-02	1.0E-03	0.24	220	--	--	--	--	0.41	6.0E-03	0.29	1,148	0.11	2.0E-03	0.11	340
May-22	2.12	4.0E-02	1.34	7,945	1.93	3.3E-02	0.92	6,563	2.05	3.3E-02	0.85	6,498	1.48	2.5E-02	0.81	5,021
Jun-22	3.54	7.3E-02	1.86	14,460	3.69	7.1E-02	1.92	14,031	4.44	7.9E-02	1.54	15,595	3.60	6.8E-02	1.36	13,440
Jul-22	4.76	0.11	2.43	20,720	4.67	9.7E-02	2.42	19,184	5.60	0.11	1.81	21,226	4.78	9.8E-02	1.90	19,371
Aug-22	4.14	9.2E-02	2.72	18,189	4.77	9.3E-02	2.54	18,480	4.93	9.3E-02	1.96	18,362	4.48	9.0E-02	1.90	17,817
Sep-22	2.88	5.9E-02	1.86	11,672	2.94	5.5E-02	1.69	10,953	3.14	5.7E-02	1.16	11,292	2.78	5.0E-02	1.46	9,960
Oct-22	4.8E-02	1.0E-03	0.10	100	--	--	--	--	0.28	4.0E-03	0.14	775	0.26	4.0E-03	0.20	727
Nov-22	--	--	--	--	0.24	4.0E-03	0.24	732	0.51	6.0E-03	0.29	1,212	0.30	4.0E-03	0.31	747
Dec-22	--	--	--	--	0.62	8.0E-03	0.68	1,530	1.16	1.5E-02	0.75	2,926	1.16	1.5E-02	1.02	2,984

1. Emissions data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system for NO_X, SO_2, and CO_2.
2. Historically measured site data from CEMS for CO.

Table B-3. Emission Factors for Turbine Combustion of Natural Gas

Pollutant	Emission Factor (lb/MMBtu, HHV Basis)	Emission Factor Basis
SO_2	6.00E-04	See Note 1
NO_X	4.49E-02	See Note 2
CO	1.82E-02	See Note 2
Total PM	1.37E-02	See Note 2
Filterable PM	3.97E-03	See Note 3
Condensable PM	9.73E-03	See Note 3
Total PM_{10}	1.37E-02	See Note 2
Total $PM_{2.5}$	1.37E-02	See Note 2
VOC	2.54E-03	See Note 2
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	See Note 1
GHGs		
CO_2	118.86	See Note 4
CH_4	2.20E-03	See Note 5
N_2O	2.20E-04	See Note 5
CO_2e	118.98	See Note 6

1. SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens.

3. Emission factors for filterable and condensable PM from natural gas combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = $F_c * U_f * MW_{CO2}$
CO_2 emission factor (lb/MMBtu) = 1,040 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

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, HHV Basis)	Emission Factor Basis
SO_2	1.51E-03	See Note 1
NO_X	1.68E-01	See Note 2
CO	3.64E-02	See Note 2
Total PM	1.70E-02	See Note 2
Filterable PM	6.12E-03	See Note 3
Condensable PM	1.09E-02	See Note 3
Total PM_{10}	1.70E-02	See Note 2
Total $PM_{2.5}$	1.70E-02	See Note 2
VOC	6.96E-03	See Note 2
Lead	1.40E-05	See Note 3
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	See Note 1
GHGs		
CO_2	162.29	See Note 4
CH_4	6.61E-03	See Note 5
N_2O	1.32E-03	See Note 5
CO_2e	162.85	See Note 6

1. Emission factor for SO_2 derived from Equation D-2 in Appendix D to 40 CFR 75.
SO_2 emission factor (lb/MMBtu) = 2.0 * Density (lb/gal) / HHV (MMBtu/gal) * $\%S_{oil}$ / 100.0
SO_2 emission factor (lb/MMBtu) = 2.0 * 7.05 (lb/gal) / 0.140 (MMBtu/gal) * 0.0015 (%S) / 100.0
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens.

3. Emission factors for lead, as well as filterable and condensable PM from fuel oil combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = F_c * U_f * MW_{CO2}
CO_2 emission factor (lb/MMBtu) = 1,420 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

5. 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.

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-5. Emission Factors for Turbine Startup/Shutdown Operations

Pollutant	Emission Factors[1] (lb/event)	Events[2]
Startup Natural Gas		
NO_X	74	227 events/yr
CO	276	
VOC	30.8	
Shutdown Natural Gas		
NO_X	76	227 events/yr
CO	82	
VOC	9.0	
Startup Fuel Oil		
NO_X	244	27 events/yr
CO	514	
VOC	57.7	
Startup/Shutdown Fuel Oil		
NO_X	286	27 events/yr
CO	314	
VOC	35.1	

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.

2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type.

Table B-6. 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]
Mar-14	4.3E-02	0.10	0.15	0.15	0.15	6.0E-03	0.55	0.30	2.7E-02	6.4E-04	1,276
Apr-14	1.5E-02	3.6E-02	5.0E-02	5.0E-02	5.0E-02	2.0E-03	0.13	--	9.3E-03	2.2E-04	438
May-14	3.8E-02	9.2E-02	0.13	0.13	0.13	6.0E-03	0.25	0.30	2.4E-02	5.7E-04	1,126
Jun-14	2.1E-02	5.1E-02	7.1E-02	7.1E-02	7.1E-02	3.0E-03	0.14	--	1.3E-02	3.1E-04	620
Jul-14	4.6E-02	0.11	0.16	0.16	0.16	7.0E-03	0.27	--	3.0E-02	7.0E-04	1,385
Aug-14	4.3E-02	0.10	0.15	0.15	0.15	6.0E-03	0.29	--	2.7E-02	6.4E-04	1,276
Sep-14	8.8E-03	2.2E-02	3.0E-02	3.0E-02	3.0E-02	1.0E-03	7.0E-02	--	5.6E-03	1.3E-04	264
Oct-14	5.0E-02	0.12	0.17	0.17	0.17	8.0E-03	0.34	0.10	3.2E-02	7.6E-04	1,504
Nov-14	4.4E-03	1.1E-02	1.5E-02	1.5E-02	1.5E-02	1.0E-03	3.9E-02	--	2.8E-03	6.7E-05	133
Dec-14	--	--	--	--	--	--	--	--	--	--	--
Jan-15	--	--	--	--	--	--	--	--	--	--	--
Feb-15	--	--	--	--	--	--	--	--	--	--	--
Mar-15	--	--	--	--	--	--	--	--	--	--	--
Apr-15	2.7E-03	6.6E-03	9.2E-03	9.2E-03	9.2E-03	--	4.9E-02	--	1.7E-03	4.1E-05	80
May-15	0.12	0.29	0.40	0.40	0.40	1.8E-02	0.97	0.30	7.5E-02	1.8E-03	3,508
Jun-15	0.14	0.35	0.49	0.49	0.49	2.2E-02	0.99	0.80	9.1E-02	2.2E-03	4,273
Jul-15	0.32	0.78	1.10	1.10	1.10	4.8E-02	2.05	2.70	0.20	4.8E-03	9,536
Aug-15	0.18	0.43	0.61	0.61	0.61	2.7E-02	1.22	2.30	0.11	2.7E-03	5,269
Sep-15	0.17	0.41	0.58	0.58	0.58	2.5E-02	1.17	0.80	0.11	2.5E-03	5,022
Oct-15	0.21	0.50	0.71	0.71	0.71	3.1E-02	1.65	0.50	0.13	3.1E-03	6,166
Nov-15	7.0E-02	0.17	0.24	0.24	0.24	1.1E-02	0.50	0.10	4.5E-02	1.1E-03	2,106
Dec-15	--	--	--	--	--	--	--	--	--	--	--
Jan-16	8.5E-03	2.1E-02	2.9E-02	2.9E-02	2.9E-02	1.0E-03	9.5E-02	--	5.4E-03	1.3E-04	254
Feb-16	7.4E-03	1.8E-02	2.5E-02	2.5E-02	2.5E-02	1.0E-03	7.4E-02	--	4.7E-03	1.1E-04	221
Mar-16	0.19	0.45	0.64	0.64	0.64	2.8E-02	1.63	0.40	0.12	2.8E-03	5,547
Apr-16	0.21	0.51	0.72	0.72	0.72	3.1E-02	1.75	1.20	0.13	3.1E-03	6,239
May-16	0.37	0.90	1.27	1.27	1.27	5.5E-02	2.90	1.70	0.23	5.5E-03	10,990
Jun-16	0.43	1.06	1.50	1.50	1.50	6.6E-02	3.01	2.00	0.28	6.6E-03	12,996
Jul-16	0.51	1.26	1.77	1.77	1.77	7.8E-02	3.50	3.60	0.33	7.8E-03	15,404
Aug-16	0.51	1.26	1.77	1.77	1.77	7.7E-02	3.36	3.60	0.33	7.7E-03	15,357
Sep-16	0.30	0.73	1.03	1.03	1.03	4.5E-02	2.18	2.30	0.19	4.5E-03	8,921
Oct-16	--	--	--	--	--	--	--	--	--	--	--
Nov-16	2.5E-02	6.1E-02	8.6E-02	8.6E-02	8.6E-02	4.0E-03	0.30	0.50	1.6E-02	3.8E-04	746
Dec-16	6.1E-02	0.15	0.21	0.21	0.21	9.0E-03	0.64	1.00	3.9E-02	9.2E-04	1,828
Jan-17	1.2E-02	2.9E-02	4.0E-02	4.0E-02	4.0E-02	2.0E-03	0.14	0.30	7.5E-03	1.8E-04	350
Feb-17	--	--	--	--	--	--	--	--	--	--	--
Mar-17	7.2E-03	1.8E-02	2.5E-02	2.5E-02	2.5E-02	1.0E-03	8.9E-02	0.20	4.6E-03	1.1E-04	216
Apr-17	4.6E-02	0.11	0.16	0.16	0.16	7.0E-03	0.42	0.50	2.9E-02	6.9E-04	1,367
May-17	0.21	0.50	0.71	0.71	0.71	3.1E-02	1.64	1.90	0.13	3.1E-03	6,171
Jun-17	0.11	0.28	0.39	0.39	0.39	1.7E-02	0.84	0.80	7.2E-02	1.7E-03	3,376
Jul-17	0.35	0.85	1.20	1.20	1.20	5.3E-02	2.51	2.90	0.22	5.3E-03	10,446
Aug-17	0.28	0.68	0.96	0.96	0.96	4.2E-02	2.05	2.80	0.18	4.2E-03	8,354
Sep-17	0.18	0.43	0.61	0.61	0.61	2.7E-02	1.39	1.70	0.11	2.7E-03	5,295
Oct-17	6.7E-02	0.16	0.23	0.23	0.23	1.0E-02	0.65	0.80	4.3E-02	1.0E-03	2,013
Nov-17	5.7E-02	0.14	0.20	0.20	0.20	9.0E-03	0.59	0.80	3.6E-02	8.6E-04	1,699
Dec-17	3.6E-03	8.8E-03	1.2E-02	1.2E-02	1.2E-02	1.0E-03	5.3E-02	0.20	2.3E-03	5.4E-05	108
Jan-18	9.9E-02	0.24	0.34	0.34	0.34	1.5E-02	0.95	1.00	6.3E-02	1.5E-03	2,960
Feb-18	--	--	--	--	--	--	--	--	--	--	--
Mar-18	8.9E-03	2.2E-02	3.1E-02	3.1E-02	3.1E-02	1.0E-03	0.10	0.10	5.7E-03	1.3E-04	267
Apr-18	1.7E-02	4.0E-02	5.7E-02	5.7E-02	5.7E-02	2.0E-03	0.15	0.20	1.1E-02	2.5E-04	494
May-18	0.29	0.72	1.01	1.01	1.01	4.4E-02	2.37	2.50	0.19	4.4E-03	8,762
Jun-18	0.36	0.89	1.25	1.25	1.25	5.5E-02	2.78	3.60	0.23	5.5E-03	10,876
Jul-18	0.45	1.10	1.55	1.55	1.55	6.8E-02	3.19	3.40	0.29	6.8E-03	13,476
Aug-18	0.46	1.12	1.57	1.57	1.57	6.9E-02	3.18	3.10	0.29	6.9E-03	13,652
Sep-18	0.57	1.39	1.96	1.96	1.96	8.6E-02	3.98	3.10	0.36	8.6E-03	16,985
Oct-18	5.7E-02	0.14	0.20	0.20	0.20	9.0E-03	0.44	0.60	3.6E-02	8.6E-04	1,698
Nov-18	2.2E-02	5.3E-02	7.5E-02	7.5E-02	7.5E-02	3.0E-03	0.28	0.60	1.4E-02	3.3E-04	649
Dec-18	5.5E-02	0.13	0.19	0.19	0.19	8.0E-03	0.57	0.90	3.5E-02	8.3E-04	1,650

Table B-6. 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]**
Jan-19	2.5E-02	6.0E-02	8.5E-02	8.5E-02	8.5E-02	4.0E-03	0.22	0.10	1.6E-02	3.7E-04	738
Feb-19	2.1E-02	5.1E-02	7.1E-02	7.1E-02	7.1E-02	3.0E-03	0.19	0.20	1.3E-02	3.1E-04	619
Mar-19	1.8E-02	4.3E-02	6.1E-02	6.1E-02	6.1E-02	3.0E-03	0.22	0.60	1.1E-02	2.7E-04	529
Apr-19	8.6E-02	0.21	0.30	0.30	0.30	1.3E-02	0.67	0.60	5.5E-02	1.3E-03	2,563
May-19	0.35	0.85	1.20	1.20	1.20	5.2E-02	2.62	2.70	0.22	5.2E-03	10,378
Jun-19	0.13	0.32	0.46	0.46	0.46	2.0E-02	1.02	1.50	8.4E-02	2.0E-03	3,958
Jul-19	0.40	0.98	1.38	1.38	1.38	6.0E-02	3.02	3.10	0.26	6.0E-03	11,984
Aug-19	0.50	1.21	1.71	1.71	1.71	7.5E-02	3.58	2.90	0.32	7.5E-03	14,844
Sep-19	0.45	1.10	1.55	1.55	1.55	6.8E-02	3.46	3.10	0.29	6.8E-03	13,499
Oct-19	9.1E-02	0.22	0.31	0.31	0.31	1.4E-02	0.70	0.70	5.8E-02	1.4E-03	2,715
Nov-19	4.5E-02	0.11	0.15	0.15	0.15	7.0E-03	0.49	1.80	2.9E-02	6.8E-04	1,340
Dec-19	3.8E-02	9.4E-02	0.13	0.13	0.13	6.0E-03	0.41	0.80	2.4E-02	5.8E-04	1,145
Jan-20	1.6E-02	4.0E-02	5.6E-02	5.6E-02	5.6E-02	2.0E-03	0.11	0.10	1.0E-02	2.4E-04	484
Feb-20	--	--	--	--	--	--	--	--	--	--	--
Mar-20	2.0E-02	4.9E-02	6.9E-02	6.9E-02	6.9E-02	3.0E-03	0.21	0.30	1.3E-02	3.0E-04	599
Apr-20	3.1E-02	7.7E-02	0.11	0.11	0.11	5.0E-03	0.25	0.20	2.0E-02	4.7E-04	940
May-20	0.23	0.55	0.78	0.78	0.78	3.4E-02	1.69	1.80	0.14	3.4E-03	6,754
Jun-20	0.29	0.70	0.98	0.98	0.98	4.3E-02	2.09	3.10	0.18	4.3E-03	8,548
Jul-20	0.50	1.23	1.73	1.73	1.73	7.6E-02	3.42	4.00	0.32	7.6E-03	15,048
Aug-20	0.46	1.14	1.60	1.60	1.60	7.0E-02	3.14	2.60	0.30	7.0E-03	13,910
Sep-20	0.18	0.44	0.62	0.62	0.62	2.7E-02	1.26	1.40	0.12	2.7E-03	5,399
Oct-20	7.4E-05	1.8E-04	2.5E-04	2.5E-04	2.5E-04	--	2.0E-03	0.10	4.7E-05	1.1E-06	2.21
Nov-20	--	--	--	--	--	--	--	--	--	--	--
Dec-20	1.4E-02	3.5E-02	4.9E-02	4.9E-02	4.9E-02	2.0E-03	0.18	0.50	9.1E-03	2.2E-04	428
Jan-21	5.5E-03	1.3E-02	1.9E-02	1.9E-02	1.9E-02	1.0E-03	0.11	0.60	3.5E-03	8.3E-05	164
Feb-21	--	--	--	--	--	--	--	--	--	--	--
Mar-21	5.0E-02	0.12	0.17	0.17	0.17	8.0E-03	0.65	1.70	3.2E-02	7.6E-04	1,508
Apr-21	7.5E-02	0.18	0.26	0.26	0.26	1.1E-02	0.62	0.70	4.8E-02	1.1E-03	2,255
May-21	0.15	0.37	0.53	0.53	0.53	2.3E-02	1.17	1.10	9.8E-02	2.3E-03	4,584
Jun-21	0.30	0.73	1.02	1.02	1.02	4.5E-02	2.08	1.80	0.19	4.5E-03	8,894
Jul-21	0.22	0.53	0.75	0.75	0.75	3.3E-02	1.49	1.20	0.14	3.3E-03	6,515
Aug-21	0.21	0.51	0.71	0.71	0.71	3.1E-02	1.61	1.60	0.13	3.1E-03	6,186
Sep-21	6.5E-02	0.16	0.22	0.22	0.22	1.0E-02	0.52	0.60	4.1E-02	9.8E-04	1,937
Oct-21	2.1E-03	5.2E-03	7.4E-03	7.4E-03	7.4E-03	--	3.7E-02	0.10	1.4E-03	3.2E-05	64
Nov-21	1.7E-02	4.0E-02	5.7E-02	5.7E-02	5.7E-02	2.0E-03	0.27	0.70	1.1E-02	2.5E-04	495
Dec-21	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--
Feb-22	--	--	--	--	--	--	--	--	--	--	--
Mar-22	--	--	--	--	--	--	--	--	--	--	--
Apr-22	7.4E-03	1.8E-02	2.5E-02	2.5E-02	2.5E-02	1.0E-03	6.6E-02	0.24	4.7E-03	1.1E-04	220
May-22	0.27	0.65	0.92	0.92	0.92	4.0E-02	2.12	1.34	0.17	4.0E-03	7,953
Jun-22	0.48	1.18	1.67	1.67	1.67	7.3E-02	3.54	1.86	0.31	7.3E-03	14,474
Jul-22	0.69	1.70	2.39	2.39	2.39	0.11	4.76	2.43	0.44	1.0E-02	20,741
Aug-22	0.61	1.49	2.10	2.10	2.10	9.2E-02	4.14	2.72	0.39	9.2E-03	18,207
Sep-22	0.39	0.96	1.35	1.35	1.35	5.9E-02	2.88	1.86	0.25	5.9E-03	11,684
Oct-22	3.3E-03	8.2E-03	1.1E-02	1.1E-02	1.1E-02	1.0E-03	4.8E-02	0.10	2.1E-03	5.0E-05	100
Nov-22	--	--	--	--	--	--	--	--	--	--	--
Dec-22	--	--	--	--	--	--	--	--	--	--	--

1. Excluding SO_2, NO_X, CO, and CO_2e, 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 site data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system. Baseline Emissions of CO from site CEMS data.

3. Baseline emissions of CO_2e are calculated using the historical CO_2 emissions data, 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-7. 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]
Mar-14	3.8E-02	9.4E-02	0.13	0.13	0.13	6.0E-03	0.43	2.80	2.5E-02	5.8E-04	1,152
Apr-14	1.7E-02	4.1E-02	5.8E-02	5.8E-02	5.8E-02	3.0E-03	0.18	0.90	1.1E-02	2.5E-04	505
May-14	0.15	0.36	0.51	0.51	0.51	2.2E-02	1.05	1.90	9.4E-02	2.2E-03	4,422
Jun-14	0.16	0.38	0.54	0.54	0.54	2.3E-02	1.04	1.90	9.9E-02	2.3E-03	4,649
Jul-14	0.25	0.60	0.85	0.85	0.85	3.7E-02	1.52	2.10	0.16	3.7E-03	7,353
Aug-14	0.33	0.80	1.13	1.13	1.13	4.9E-02	2.31	2.70	0.21	4.9E-03	9,791
Sep-14	0.18	0.43	0.61	0.61	0.61	2.7E-02	1.22	1.80	0.11	2.7E-03	5,255
Oct-14	0.24	0.60	0.84	0.84	0.84	3.7E-02	1.76	1.80	0.16	3.7E-03	7,322
Nov-14	3.7E-02	9.0E-02	0.13	0.13	0.13	6.0E-03	0.41	0.90	2.4E-02	5.6E-04	1,103
Dec-14	1.2E-02	2.9E-02	4.1E-02	4.1E-02	4.1E-02	2.0E-03	0.15	0.20	7.5E-03	1.8E-04	352
Jan-15	3.0E-02	7.4E-02	0.10	0.10	0.10	5.0E-03	0.44	0.80	1.9E-02	4.6E-04	903
Feb-15	--	--	--	--	--	--	--	--	--	--	--
Mar-15	4.8E-03	1.2E-02	1.6E-02	1.6E-02	1.6E-02	1.0E-03	6.0E-02	0.20	3.0E-03	7.2E-05	142
Apr-15	7.1E-02	0.17	0.24	0.24	0.24	1.1E-02	0.54	0.40	4.5E-02	1.1E-03	2,121
May-15	0.39	0.94	1.33	1.33	1.33	5.8E-02	2.87	3.00	0.25	5.8E-03	11,547
Jun-15	0.30	0.74	1.04	1.04	1.04	4.6E-02	2.28	2.50	0.19	4.5E-03	9,022
Jul-15	0.51	1.24	1.74	1.74	1.74	7.6E-02	3.72	3.50	0.32	7.6E-03	15,123
Aug-15	0.41	1.00	1.40	1.40	1.40	6.2E-02	2.93	3.30	0.26	6.1E-03	12,195
Sep-15	0.33	0.82	1.15	1.15	1.15	5.1E-02	2.48	2.10	0.21	5.1E-03	10,015
Oct-15	0.38	0.94	1.33	1.33	1.33	5.8E-02	3.23	2.30	0.25	5.8E-03	11,528
Nov-15	0.17	0.42	0.59	0.59	0.59	2.6E-02	1.29	1.00	0.11	2.6E-03	5,120
Dec-15	--	--	--	--	--	--	--	--	--	--	--
Jan-16	--	--	--	--	--	--	--	--	--	--	--
Feb-16	--	--	--	--	--	--	--	--	--	--	--
Mar-16	--	--	--	--	--	--	--	--	--	--	--
Apr-16	0.30	0.74	1.04	1.04	1.04	4.5E-02	2.70	1.70	0.19	4.5E-03	9,014
May-16	0.68	1.66	2.33	2.33	2.33	0.10	5.77	3.90	0.43	1.0E-02	20,250
Jun-16	0.62	1.52	2.15	2.15	2.15	9.4E-02	4.61	3.40	0.40	9.4E-03	18,649
Jul-16	0.45	1.11	1.56	1.56	1.56	6.8E-02	3.05	3.10	0.29	6.8E-03	13,568
Aug-16	0.48	1.18	1.67	1.67	1.67	7.3E-02	3.32	3.40	0.31	7.3E-03	14,461
Sep-16	0.29	0.72	1.01	1.01	1.01	4.4E-02	2.21	2.60	0.19	4.4E-03	8,804
Oct-16	--	--	--	--	--	--	--	--	--	--	--
Nov-16	1.7E-02	4.1E-02	5.8E-02	5.8E-02	5.8E-02	3.0E-03	0.16	0.20	1.1E-02	2.5E-04	500
Dec-16	3.9E-02	9.6E-02	0.14	0.14	0.14	6.0E-03	0.41	0.90	2.5E-02	5.9E-04	1,175
Jan-17	3.2E-02	7.8E-02	0.11	0.11	0.11	5.0E-03	0.31	0.50	2.0E-02	4.8E-04	958
Feb-17	--	--	--	--	--	--	--	--	--	--	--
Mar-17	1.6E-02	3.9E-02	5.5E-02	5.5E-02	5.5E-02	2.0E-03	0.17	0.20	1.0E-02	2.4E-04	479
Apr-17	4.6E-02	0.11	0.16	0.16	0.16	7.0E-03	0.47	0.30	3.0E-02	7.0E-04	1,392
May-17	0.19	0.48	0.67	0.67	0.67	2.9E-02	1.50	1.70	0.12	2.9E-03	5,832
Jun-17	8.2E-02	0.20	0.28	0.28	0.28	1.2E-02	0.63	0.70	5.2E-02	1.2E-03	2,457
Jul-17	0.32	0.79	1.12	1.12	1.12	4.9E-02	2.40	3.10	0.21	4.9E-03	9,714
Aug-17	0.24	0.59	0.83	0.83	0.83	3.6E-02	1.87	2.50	0.15	3.6E-03	7,228
Sep-17	0.15	0.36	0.51	0.51	0.51	2.2E-02	1.14	1.80	9.4E-02	2.2E-03	4,404
Oct-17	9.3E-03	2.3E-02	3.2E-02	3.2E-02	3.2E-02	1.0E-03	7.8E-02	0.10	5.9E-03	1.4E-04	278
Nov-17	7.0E-02	0.17	0.24	0.24	0.24	1.0E-02	0.60	0.80	4.4E-02	1.0E-03	2,082
Dec-17	--	--	--	--	--	--	--	--	--	--	--
Jan-18	5.1E-02	0.12	0.18	0.18	0.18	8.0E-03	0.52	0.80	3.2E-02	7.7E-04	1,521
Feb-18	--	--	--	--	--	--	--	--	--	--	--
Mar-18	--	--	--	--	--	--	--	--	--	--	--
Apr-18	8.7E-03	2.1E-02	3.0E-02	3.0E-02	3.0E-02	1.0E-03	8.1E-02	0.20	5.5E-03	1.3E-04	260
May-18	0.24	0.59	0.84	0.84	0.84	3.7E-02	1.79	1.90	0.16	3.7E-03	7,276
Jun-18	0.34	0.83	1.16	1.16	1.16	5.1E-02	2.30	2.80	0.22	5.1E-03	10,116
Jul-18	0.43	1.04	1.47	1.47	1.47	6.4E-02	2.81	3.30	0.27	6.4E-03	12,751
Aug-18	0.43	1.04	1.47	1.47	1.47	6.4E-02	2.98	3.00	0.27	6.4E-03	12,754
Sep-18	0.57	1.39	1.96	1.96	1.96	8.6E-02	3.96	3.50	0.36	8.6E-03	16,993
Oct-18	3.1E-02	7.5E-02	0.11	0.11	0.11	5.0E-03	0.24	0.30	2.0E-02	4.6E-04	921
Nov-18	7.9E-05	1.9E-04	2.7E-04	2.7E-04	2.7E-04	--	1.0E-03	0.10	5.0E-05	1.2E-06	2.35
Dec-18	1.6E-02	3.9E-02	5.4E-02	5.4E-02	5.4E-02	2.0E-03	0.25	0.60	1.0E-02	2.4E-04	473

Table B-7. 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-19	4.7E-02	0.12	0.16	0.16	0.16	7.0E-03	0.48	0.60	3.0E-02	7.1E-04	1,412
Feb-19	2.3E-02	5.7E-02	8.1E-02	8.1E-02	8.1E-02	4.0E-03	0.23	0.30	1.5E-02	3.5E-04	702
Mar-19	1.1E-02	2.7E-02	3.8E-02	3.8E-02	3.8E-02	2.0E-03	0.13	0.20	7.1E-03	1.7E-04	331
Apr-19	5.2E-02	0.13	0.18	0.18	0.18	8.0E-03	0.39	0.40	3.3E-02	7.9E-04	1,568
May-19	0.31	0.77	1.08	1.08	1.08	4.8E-02	2.38	3.10	0.20	4.8E-03	9,422
Jun-19	0.18	0.45	0.63	0.63	0.63	2.8E-02	1.34	2.00	0.12	2.8E-03	5,456
Jul-19	0.44	1.09	1.53	1.53	1.53	6.7E-02	3.14	3.40	0.28	6.7E-03	13,278
Aug-19	0.49	1.20	1.69	1.69	1.69	7.4E-02	3.36	2.90	0.31	7.4E-03	14,693
Sep-19	0.45	1.09	1.54	1.54	1.54	6.7E-02	3.14	2.60	0.29	6.7E-03	13,368
Oct-19	7.7E-02	0.19	0.27	0.27	0.27	1.2E-02	0.52	0.40	5.0E-02	1.2E-03	2,320
Nov-19	4.3E-02	0.10	0.15	0.15	0.15	6.0E-03	0.52	2.30	2.7E-02	6.4E-04	1,276
Dec-19	3.8E-02	9.4E-02	0.13	0.13	0.13	6.0E-03	0.40	0.70	2.5E-02	5.8E-04	1,148
Jan-20	--	--	--	--	--	--	--	--	--	--	--
Feb-20	--	--	--	--	--	--	--	--	--	--	--
Mar-20	--	--	--	--	--	--	--	--	--	--	--
Apr-20	2.9E-02	7.2E-02	0.10	0.10	0.10	4.0E-03	0.22	0.20	1.9E-02	4.4E-04	879
May-20	0.21	0.52	0.73	0.73	0.73	3.2E-02	1.50	1.90	0.13	3.2E-03	6,318
Jun-20	0.34	0.84	1.18	1.18	1.18	5.2E-02	2.33	3.40	0.22	5.2E-03	10,283
Jul-20	0.48	1.17	1.64	1.64	1.64	7.2E-02	3.00	2.80	0.30	7.2E-03	14,257
Aug-20	0.50	1.21	1.71	1.71	1.71	7.5E-02	3.20	2.70	0.32	7.5E-03	14,840
Sep-20	0.19	0.48	0.67	0.67	0.67	2.9E-02	1.31	1.20	0.12	2.9E-03	5,813
Oct-20	7.0E-05	1.7E-04	2.4E-04	2.4E-04	2.4E-04	--	1.0E-03	0.10	4.5E-05	1.1E-06	2.09
Nov-20	--	--	--	--	--	--	--	--	--	--	--
Dec-20	1.7E-02	4.2E-02	6.0E-02	6.0E-02	6.0E-02	3.0E-03	0.19	0.40	1.1E-02	2.6E-04	517
Jan-21	2.5E-03	6.2E-03	8.7E-03	8.7E-03	8.7E-03	--	3.6E-02	0.10	1.6E-03	3.8E-05	76
Feb-21	7.3E-03	1.8E-02	2.5E-02	2.5E-02	2.5E-02	1.0E-03	6.8E-02	0.10	4.7E-03	1.1E-04	220
Mar-21	2.7E-02	6.6E-02	9.2E-02	9.2E-02	9.2E-02	4.0E-03	0.31	0.90	1.7E-02	4.0E-04	803
Apr-21	9.2E-02	0.23	0.32	0.32	0.32	1.4E-02	0.69	0.60	5.9E-02	1.4E-03	2,761
May-21	0.16	0.39	0.55	0.55	0.55	2.4E-02	1.14	0.90	0.10	2.4E-03	4,751
Jun-21	0.29	0.70	0.98	0.98	0.98	4.3E-02	2.02	1.50	0.18	4.3E-03	8,545
Jul-21	0.23	0.56	0.78	0.78	0.78	3.4E-02	1.53	2.20	0.15	3.4E-03	6,799
Aug-21	0.22	0.55	0.77	0.77	0.77	3.4E-02	1.86	1.60	0.14	3.4E-03	6,725
Sep-21	7.9E-02	0.19	0.27	0.27	0.27	1.2E-02	0.77	0.70	5.1E-02	1.2E-03	2,379
Oct-21	2.3E-03	5.5E-03	7.8E-03	7.8E-03	7.8E-03	--	2.9E-02	--	1.4E-03	3.4E-05	67
Nov-21	1.2E-02	2.8E-02	4.0E-02	4.0E-02	4.0E-02	2.0E-03	0.18	0.30	7.4E-03	1.7E-04	346
Dec-21	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--
Feb-22	--	--	--	--	--	--	--	--	--	--	--
Mar-22	--	--	--	--	--	--	--	--	--	--	--
Apr-22	--	--	--	--	--	--	--	--	--	--	--
May-22	0.22	0.54	0.76	0.76	0.76	3.3E-02	1.93	0.92	0.14	3.3E-03	6,569
Jun-22	0.47	1.15	1.62	1.62	1.62	7.1E-02	3.69	1.92	0.30	7.1E-03	14,045
Jul-22	0.64	1.57	2.21	2.21	2.21	9.7E-02	4.67	2.42	0.41	9.7E-03	19,203
Aug-22	0.62	1.51	2.13	2.13	2.13	9.3E-02	4.77	2.54	0.39	9.3E-03	18,499
Sep-22	0.37	0.90	1.26	1.26	1.26	5.5E-02	2.94	1.69	0.23	5.5E-03	10,964
Oct-22	--	--	--	--	--	--	--	--	--	--	--
Nov-22	2.4E-02	6.0E-02	8.4E-02	8.4E-02	8.4E-02	4.0E-03	0.24	0.24	1.6E-02	3.7E-04	733
Dec-22	5.1E-02	0.13	0.18	0.18	0.18	8.0E-03	0.62	0.68	3.3E-02	7.7E-04	1,532

1. Excluding SO_2, NO_X, CO, and CO_2e, 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 site data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system. Baseline Emissions of CO from site CEMS data.

3. Baseline emissions of CO_2e are calculated using the historical CO_2 emissions data, 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. 3 (tons/month)[1,2]

Month	T3 - Combustion Turbine No. 3										
	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]
Mar-14	4.4E-02	0.11	0.15	0.15	0.15	7.0E-03	0.70	5.60	2.8E-02	6.6E-04	1,308
Apr-14	1.8E-02	4.4E-02	6.1E-02	6.1E-02	6.1E-02	3.0E-03	0.17	0.50	1.1E-02	2.7E-04	532
May-14	6.4E-02	0.16	0.22	0.22	0.22	1.0E-02	0.59	1.00	4.1E-02	9.7E-04	1,914
Jun-14	0.11	0.27	0.38	0.38	0.38	1.7E-02	0.73	1.20	7.1E-02	1.7E-03	3,310
Jul-14	0.23	0.57	0.80	0.80	0.80	3.5E-02	1.47	2.40	0.15	3.5E-03	6,956
Aug-14	0.23	0.56	0.78	0.78	0.78	3.4E-02	1.50	2.20	0.15	3.4E-03	6,806
Sep-14	6.9E-02	0.17	0.24	0.24	0.24	1.0E-02	0.43	0.80	4.4E-02	1.0E-03	2,080
Oct-14	0.22	0.54	0.77	0.77	0.77	3.4E-02	1.34	1.10	0.14	3.4E-03	6,647
Nov-14	5.2E-02	0.13	0.18	0.18	0.18	8.0E-03	0.56	0.80	3.3E-02	7.9E-04	1,561
Dec-14	1.1E-02	2.7E-02	3.8E-02	3.8E-02	3.8E-02	2.0E-03	0.11	0.50	7.1E-03	1.7E-04	333
Jan-15	--	--	--	--	--	--	--	--	--	--	--
Feb-15	4.4E-03	1.1E-02	1.5E-02	1.5E-02	1.5E-02	1.0E-03	7.1E-02	0.80	2.8E-03	6.6E-05	132
Mar-15	--	--	--	--	--	--	--	--	--	--	--
Apr-15	6.4E-02	0.16	0.22	0.22	0.22	1.0E-02	0.43	0.40	4.1E-02	9.7E-04	1,916
May-15	0.30	0.74	1.05	1.05	1.05	4.6E-02	2.10	3.20	0.19	4.6E-03	9,080
Jun-15	0.22	0.55	0.77	0.77	0.77	3.4E-02	1.54	2.30	0.14	3.4E-03	6,690
Jul-15	0.16	0.38	0.54	0.54	0.54	2.4E-02	1.15	2.50	0.10	2.4E-03	4,689
Aug-15	0.12	0.29	0.40	0.40	0.40	1.8E-02	0.91	1.30	7.5E-02	1.8E-03	3,504
Sep-15	8.9E-02	0.22	0.31	0.31	0.31	1.3E-02	0.72	1.60	5.7E-02	1.3E-03	2,674
Oct-15	1.6E-02	3.9E-02	5.5E-02	5.5E-02	5.5E-02	2.0E-03	0.17	1.00	1.0E-02	2.4E-04	478
Nov-15	2.2E-02	5.4E-02	7.6E-02	7.6E-02	7.6E-02	3.0E-03	0.16	0.10	1.4E-02	3.3E-04	658
Dec-15	--	--	--	--	--	--	--	--	--	--	--
Jan-16	4.5E-03	1.1E-02	1.6E-02	1.6E-02	1.6E-02	1.0E-03	7.7E-02	0.20	2.9E-03	6.8E-05	135
Feb-16	3.2E-02	7.7E-02	0.11	0.11	0.11	5.0E-03	0.32	0.60	2.0E-02	4.8E-04	947
Mar-16	0.22	0.53	0.74	0.74	0.74	3.3E-02	1.83	1.70	0.14	3.3E-03	6,452
Apr-16	0.21	0.52	0.74	0.74	0.74	3.2E-02	1.60	1.40	0.14	3.2E-03	6,420
May-16	0.62	1.51	2.13	2.13	2.13	9.3E-02	4.67	4.30	0.39	9.3E-03	18,466
Jun-16	0.59	1.46	2.05	2.05	2.05	9.0E-02	4.14	4.50	0.38	9.0E-03	17,809
Jul-16	0.65	1.59	2.24	2.24	2.24	9.8E-02	4.38	4.20	0.42	9.8E-03	19,491
Aug-16	0.65	1.60	2.26	2.26	2.26	9.9E-02	4.48	3.90	0.42	9.9E-03	19,583
Sep-16	0.49	1.20	1.68	1.68	1.68	7.4E-02	3.60	3.50	0.31	7.4E-03	14,617
Oct-16	2.6E-02	6.2E-02	8.8E-02	8.8E-02	8.8E-02	4.0E-03	0.20	0.20	1.6E-02	3.9E-04	764
Nov-16	4.7E-02	0.12	0.16	0.16	0.16	7.0E-03	0.46	0.70	3.0E-02	7.1E-04	1,413
Dec-16	0.11	0.27	0.38	0.38	0.38	1.7E-02	1.17	1.20	7.1E-02	1.7E-03	3,323
Jan-17	--	--	--	--	--	--	--	--	--	--	--
Feb-17	--	--	--	--	--	--	--	--	--	--	--
Mar-17	--	--	--	--	--	--	--	--	--	--	--
Apr-17	0.12	0.29	0.41	0.41	0.41	1.8E-02	1.15	1.30	7.6E-02	1.8E-03	3,572
May-17	0.16	0.40	0.56	0.56	0.56	2.5E-02	1.27	1.40	0.10	2.5E-03	4,859
Jun-17	6.7E-02	0.17	0.23	0.23	0.23	1.0E-02	0.52	0.60	4.3E-02	1.0E-03	2,018
Jul-17	0.29	0.72	1.01	1.01	1.01	4.4E-02	2.26	2.60	0.19	4.4E-03	8,753
Aug-17	0.25	0.62	0.87	0.87	0.87	3.8E-02	1.80	2.20	0.16	3.8E-03	7,527
Sep-17	0.16	0.39	0.54	0.54	0.54	2.4E-02	1.15	1.00	0.10	2.4E-03	4,712
Oct-17	8.8E-03	2.1E-02	3.0E-02	3.0E-02	3.0E-02	1.0E-03	7.3E-02	0.10	5.6E-03	1.3E-04	262
Nov-17	2.8E-02	6.9E-02	9.7E-02	9.7E-02	9.7E-02	4.0E-03	0.24	0.30	1.8E-02	4.3E-04	847
Dec-17	6.6E-03	1.6E-02	2.3E-02	2.3E-02	2.3E-02	1.0E-03	7.0E-02	0.20	4.2E-03	9.9E-05	197
Jan-18	4.8E-02	0.12	0.16	0.16	0.16	7.0E-03	0.58	0.70	3.1E-02	7.2E-04	1,431
Feb-18	--	--	--	--	--	--	--	--	--	--	--
Mar-18	--	--	--	--	--	--	--	--	--	--	--
Apr-18	4.5E-03	1.1E-02	1.5E-02	1.5E-02	1.5E-02	1.0E-03	7.1E-02	0.10	2.9E-03	6.8E-05	134
May-18	0.21	0.52	0.73	0.73	0.73	3.2E-02	1.88	1.80	0.14	3.2E-03	6,381
Jun-18	0.31	0.75	1.06	1.06	1.06	4.6E-02	2.24	2.90	0.20	4.6E-03	9,170
Jul-18	0.40	0.97	1.36	1.36	1.36	6.0E-02	2.85	2.50	0.25	6.0E-03	11,848
Aug-18	0.41	1.01	1.42	1.42	1.42	6.2E-02	2.90	3.20	0.26	6.2E-03	12,339
Sep-18	0.52	1.28	1.80	1.80	1.80	7.9E-02	3.86	3.40	0.33	7.9E-03	15,673
Oct-18	2.1E-02	5.0E-02	7.1E-02	7.1E-02	7.1E-02	3.0E-03	0.19	0.40	1.3E-02	3.1E-04	615
Nov-18	--	--	--	--	--	--	--	--	--	--	--
Dec-18	2.0E-02	4.8E-02	6.8E-02	6.8E-02	6.8E-02	3.0E-03	0.48	0.70	1.3E-02	3.0E-04	589

Table B-8. Historical Actual Monthly Emissions from Combustion Turbine No. 3 (tons/month)[1,2]

Month	T3 - Combustion Turbine No. 3										
	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-19	3.7E-02	9.2E-02	0.13	0.13	0.13	6.0E-03	0.44	0.60	2.4E-02	5.7E-04	1,122
Feb-19	7.8E-03	1.9E-02	2.7E-02	2.7E-02	2.7E-02	1.0E-03	8.4E-02	0.30	5.0E-03	1.2E-04	235
Mar-19	5.3E-02	0.13	0.18	0.18	0.18	8.0E-03	0.58	1.00	3.4E-02	8.1E-04	1,599
Apr-19	0.11	0.26	0.37	0.37	0.37	1.6E-02	0.88	0.80	6.9E-02	1.6E-03	3,231
May-19	0.28	0.68	0.96	0.96	0.96	4.2E-02	2.13	2.70	0.18	4.2E-03	8,378
Jun-19	0.19	0.46	0.65	0.65	0.65	2.8E-02	1.41	1.50	0.12	2.8E-03	5,625
Jul-19	0.40	0.99	1.40	1.40	1.40	6.1E-02	2.82	2.80	0.26	6.1E-03	12,117
Aug-19	0.49	1.21	1.70	1.70	1.70	7.5E-02	3.37	3.30	0.32	7.5E-03	14,780
Sep-19	0.43	1.05	1.48	1.48	1.48	6.5E-02	3.17	3.00	0.27	6.5E-03	12,820
Oct-19	9.4E-02	0.23	0.32	0.32	0.32	1.4E-02	0.78	2.60	6.0E-02	1.4E-03	2,802
Nov-19	--	--	--	--	--	--	--	--	--	--	--
Dec-19	4.7E-02	0.11	0.16	0.16	0.16	7.0E-03	0.56	0.90	3.0E-02	7.0E-04	1,393
Jan-20	--	--	--	--	--	--	--	--	--	--	--
Feb-20	1.5E-04	3.7E-04	5.2E-04	5.2E-04	5.2E-04	--	4.0E-03	0.10	9.6E-05	2.3E-06	4.50
Mar-20	6.0E-03	1.5E-02	2.1E-02	2.1E-02	2.1E-02	1.0E-03	6.6E-02	0.10	3.9E-03	9.1E-05	180
Apr-20	2.2E-02	5.4E-02	7.6E-02	7.6E-02	7.6E-02	3.0E-03	0.17	0.10	1.4E-02	3.3E-04	661
May-20	0.19	0.47	0.67	0.67	0.67	2.9E-02	1.42	1.40	0.12	2.9E-03	5,776
Jun-20	0.36	0.88	1.23	1.23	1.23	5.4E-02	2.58	2.60	0.23	5.4E-03	10,716
Jul-20	0.46	1.12	1.58	1.58	1.58	6.9E-02	3.29	2.60	0.29	6.9E-03	13,719
Aug-20	0.49	1.20	1.69	1.69	1.69	7.4E-02	3.60	2.30	0.31	7.4E-03	14,677
Sep-20	0.20	0.48	0.68	0.68	0.68	3.0E-02	1.45	0.90	0.13	3.0E-03	5,908
Oct-20	0.10	0.25	0.35	0.35	0.35	1.5E-02	0.78	0.50	6.4E-02	1.5E-03	3,011
Nov-20	9.5E-02	0.23	0.33	0.33	0.33	1.4E-02	0.83	0.70	6.1E-02	1.4E-03	2,834
Dec-20	--	--	--	--	--	--	--	--	--	--	--
Jan-21	7.8E-05	1.9E-04	2.7E-04	2.7E-04	2.7E-04	--	2.0E-03	0.10	5.0E-05	1.2E-06	2.33
Feb-21	2.5E-03	6.1E-03	8.5E-03	8.5E-03	8.5E-03	--	7.6E-02	0.20	1.6E-03	3.7E-05	74
Mar-21	2.4E-02	6.0E-02	8.4E-02	8.4E-02	8.4E-02	4.0E-03	0.30	0.60	1.6E-02	3.7E-04	731
Apr-21	9.0E-02	0.22	0.31	0.31	0.31	1.4E-02	0.77	0.70	5.7E-02	1.4E-03	2,685
May-21	0.17	0.40	0.57	0.57	0.57	2.5E-02	1.27	1.10	0.11	2.5E-03	4,949
Jun-21	0.27	0.65	0.92	0.92	0.92	4.0E-02	1.91	1.30	0.17	4.0E-03	7,972
Jul-21	0.22	0.53	0.74	0.74	0.74	3.2E-02	1.45	1.00	0.14	3.2E-03	6,444
Aug-21	0.20	0.50	0.71	0.71	0.71	3.1E-02	1.59	1.30	0.13	3.1E-03	6,131
Sep-21	4.1E-02	1.0E-01	0.14	0.14	0.14	6.0E-03	0.35	0.20	2.6E-02	6.2E-04	1,222
Oct-21	0.17	0.42	0.59	0.59	0.59	2.6E-02	1.37	0.80	0.11	2.6E-03	5,132
Nov-21	6.8E-03	1.7E-02	2.4E-02	2.4E-02	2.4E-02	1.0E-03	8.0E-02	0.10	4.4E-03	1.0E-04	205
Dec-21	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--
Feb-22	7.9E-05	1.9E-04	2.7E-04	2.7E-04	2.7E-04	--	2.0E-03	0.10	5.1E-05	1.2E-06	2.38
Mar-22	--	--	--	--	--	--	--	--	--	--	--
Apr-22	3.8E-02	9.4E-02	0.13	0.13	0.13	6.0E-03	0.41	0.29	2.5E-02	5.8E-04	1,150
May-22	0.22	0.53	0.75	0.75	0.75	3.3E-02	2.05	0.85	0.14	3.3E-03	6,505
Jun-22	0.52	1.28	1.80	1.80	1.80	7.9E-02	4.44	1.54	0.33	7.9E-03	15,611
Jul-22	0.71	1.74	2.45	2.45	2.45	0.11	5.60	1.81	0.45	1.1E-02	21,248
Aug-22	0.61	1.50	2.12	2.12	2.12	9.3E-02	4.93	1.96	0.39	9.3E-03	18,381
Sep-22	0.38	0.92	1.30	1.30	1.30	5.7E-02	3.14	1.16	0.24	5.7E-03	11,304
Oct-22	2.6E-02	6.3E-02	8.9E-02	8.9E-02	8.9E-02	4.0E-03	0.28	0.14	1.7E-02	3.9E-04	776
Nov-22	4.1E-02	9.9E-02	0.14	0.14	0.14	6.0E-03	0.51	0.29	2.6E-02	6.1E-04	1,213
Dec-22	9.8E-02	0.24	0.34	0.34	0.34	1.5E-02	1.16	0.75	6.3E-02	1.5E-03	2,929

1. Excluding SO_2, NO_X, CO, and CO_2e, 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 site data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system. Baseline Emissions of CO from site CEMS data.

3. Baseline emissions of CO_2e are calculated using the historical CO_2 emissions data, 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. 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]
Mar-14	3.5E-02	8.5E-02	0.12	0.12	0.12	5.0E-03	0.44	3.30	2.2E-02	5.3E-04	1,042
Apr-14	1.2E-02	3.0E-02	4.3E-02	4.3E-02	4.3E-02	2.0E-03	0.13	0.30	7.9E-03	1.9E-04	372
May-14	0.10	0.25	0.35	0.35	0.35	1.5E-02	0.80	1.70	6.5E-02	1.5E-03	3,040
Jun-14	0.14	0.34	0.48	0.48	0.48	2.1E-02	0.99	1.40	8.9E-02	2.1E-03	4,189
Jul-14	0.20	0.49	0.69	0.69	0.69	3.0E-02	1.37	1.90	0.13	3.0E-03	5,979
Aug-14	0.24	0.60	0.84	0.84	0.84	3.7E-02	1.77	2.50	0.16	3.7E-03	7,336
Sep-14	9.2E-02	0.22	0.32	0.32	0.32	1.4E-02	0.70	1.30	5.9E-02	1.4E-03	2,748
Oct-14	0.22	0.53	0.75	0.75	0.75	3.3E-02	1.62	1.90	0.14	3.3E-03	6,505
Nov-14	7.1E-02	0.17	0.25	0.25	0.25	1.1E-02	0.79	1.20	4.6E-02	1.1E-03	2,134
Dec-14	6.1E-03	1.5E-02	2.1E-02	2.1E-02	2.1E-02	1.0E-03	7.2E-02	0.10	3.9E-03	9.1E-05	181
Jan-15	--	--	--	--	--	--	--	--	--	--	--
Feb-15	--	--	--	--	--	--	--	--	--	--	--
Mar-15	--	--	--	--	--	--	--	--	--	--	--
Apr-15	--	--	--	--	--	--	--	--	--	--	--
May-15	0.25	0.62	0.87	0.87	0.87	3.8E-02	1.89	2.20	0.16	3.8E-03	7,564
Jun-15	0.25	0.61	0.86	0.86	0.86	3.8E-02	1.69	2.00	0.16	3.8E-03	7,499
Jul-15	0.49	1.20	1.68	1.68	1.68	7.4E-02	3.12	3.00	0.31	7.4E-03	14,629
Aug-15	0.41	1.00	1.41	1.41	1.41	6.2E-02	2.78	3.00	0.26	6.2E-03	12,223
Sep-15	0.32	0.78	1.10	1.10	1.10	4.8E-02	2.18	2.20	0.20	4.8E-03	9,530
Oct-15	6.4E-02	0.16	0.22	0.22	0.22	1.0E-02	0.52	0.70	4.1E-02	9.6E-04	1,903
Nov-15	0.11	0.28	0.39	0.39	0.39	1.7E-02	0.74	0.70	7.2E-02	1.7E-03	3,383
Dec-15	--	--	--	--	--	--	--	--	--	--	--
Jan-16	4.4E-03	1.1E-02	1.5E-02	1.5E-02	1.5E-02	1.0E-03	6.3E-02	0.10	2.8E-03	6.6E-05	132
Feb-16	4.0E-02	9.7E-02	0.14	0.14	0.14	6.0E-03	0.42	0.80	2.5E-02	6.0E-04	1,191
Mar-16	0.24	0.60	0.84	0.84	0.84	3.7E-02	2.00	1.80	0.16	3.7E-03	7,279
Apr-16	0.18	0.44	0.62	0.62	0.62	2.7E-02	1.41	1.20	0.11	2.7E-03	5,363
May-16	0.58	1.41	1.98	1.98	1.98	8.7E-02	4.40	4.10	0.37	8.7E-03	17,233
Jun-16	0.60	1.47	2.07	2.07	2.07	9.0E-02	4.29	3.70	0.38	9.0E-03	17,939
Jul-16	0.65	1.60	2.25	2.25	2.25	9.9E-02	4.36	4.00	0.42	9.9E-03	19,556
Aug-16	0.61	1.50	2.11	2.11	2.11	9.2E-02	3.99	3.40	0.39	9.2E-03	18,316
Sep-16	0.48	1.17	1.65	1.65	1.65	7.2E-02	3.46	3.30	0.31	7.2E-03	14,361
Oct-16	1.6E-02	4.0E-02	5.7E-02	5.7E-02	5.7E-02	2.0E-03	0.14	0.10	1.1E-02	2.5E-04	493
Nov-16	3.4E-02	8.4E-02	0.12	0.12	0.12	5.0E-03	0.39	0.40	2.2E-02	5.2E-04	1,024
Dec-16	1.0E-01	0.24	0.34	0.34	0.34	1.5E-02	1.03	1.00	6.4E-02	1.5E-03	2,986
Jan-17	8.8E-02	0.21	0.30	0.30	0.30	1.3E-02	0.86	0.90	5.6E-02	1.3E-03	2,630
Feb-17	6.5E-03	1.6E-02	2.2E-02	2.2E-02	2.2E-02	1.0E-03	7.6E-02	0.10	4.1E-03	9.8E-05	194
Mar-17	4.2E-02	0.10	0.15	0.15	0.15	6.0E-03	0.42	0.30	2.7E-02	6.4E-04	1,261
Apr-17	0.29	0.72	1.01	1.01	1.01	4.4E-02	2.16	1.90	0.19	4.4E-03	8,784
May-17	0.40	0.99	1.39	1.39	1.39	6.1E-02	3.25	2.30	0.26	6.1E-03	12,113
Jun-17	0.24	0.58	0.81	0.81	0.81	3.6E-02	1.56	1.80	0.15	3.6E-03	7,065
Jul-17	0.51	1.24	1.75	1.75	1.75	7.6E-02	3.33	3.10	0.32	7.6E-03	15,160
Aug-17	0.39	0.96	1.36	1.36	1.36	6.0E-02	2.81	3.70	0.25	6.0E-03	11,804
Sep-17	0.29	0.70	0.99	0.99	0.99	4.3E-02	2.09	2.10	0.18	4.3E-03	8,571
Oct-17	0.17	0.42	0.59	0.59	0.59	2.6E-02	1.44	2.50	0.11	2.6E-03	5,116
Nov-17	6.8E-02	0.17	0.23	0.23	0.23	1.0E-02	0.54	0.60	4.3E-02	1.0E-03	2,025
Dec-17	--	--	--	--	--	--	--	--	--	--	--
Jan-18	--	--	--	--	--	--	--	--	--	--	--
Feb-18	--	--	--	--	--	--	--	--	--	--	--
Mar-18	--	--	--	--	--	--	--	--	--	--	--
Apr-18	1.0E-02	2.5E-02	3.5E-02	3.5E-02	3.5E-02	2.0E-03	0.12	0.50	6.5E-03	1.5E-04	306
May-18	0.48	1.17	1.65	1.65	1.65	7.2E-02	3.84	3.80	0.31	7.2E-03	14,303
Jun-18	0.27	0.67	0.95	0.95	0.95	4.1E-02	2.31	3.40	0.18	4.1E-03	8,207
Jul-18	0.36	0.88	1.23	1.23	1.23	5.4E-02	2.72	2.90	0.23	5.4E-03	10,725
Aug-18	0.39	0.95	1.34	1.34	1.34	5.9E-02	3.10	3.30	0.25	5.9E-03	11,674
Sep-18	0.50	1.23	1.74	1.74	1.74	7.6E-02	3.99	3.90	0.32	7.6E-03	15,094
Oct-18	0.11	0.26	0.37	0.37	0.37	1.6E-02	0.89	1.00	6.9E-02	1.6E-03	3,233
Nov-18	2.1E-02	5.1E-02	7.2E-02	7.2E-02	7.2E-02	3.0E-03	0.26	0.50	1.3E-02	3.1E-04	624
Dec-18	6.0E-02	0.15	0.21	0.21	0.21	9.0E-03	0.65	1.20	3.8E-02	9.0E-04	1,790

Table B-9. 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-19	5.4E-02	0.13	0.19	0.19	0.19	8.0E-03	0.69	1.00	3.5E-02	8.2E-04	1,621
Feb-19	1.4E-02	3.4E-02	4.8E-02	4.8E-02	4.8E-02	2.0E-03	0.15	0.50	8.9E-03	2.1E-04	418
Mar-19	9.1E-02	0.22	0.31	0.31	0.31	1.4E-02	0.99	1.20	5.8E-02	1.4E-03	2,729
Apr-19	0.13	0.32	0.45	0.45	0.45	2.0E-02	1.07	1.10	8.3E-02	2.0E-03	3,887
May-19	0.21	0.50	0.71	0.71	0.71	3.1E-02	1.62	1.60	0.13	3.1E-03	6,146
Jun-19	0.24	0.58	0.82	0.82	0.82	3.6E-02	1.83	2.00	0.15	3.6E-03	7,089
Jul-19	0.42	1.02	1.44	1.44	1.44	6.3E-02	2.97	3.10	0.27	6.3E-03	12,477
Aug-19	0.46	1.14	1.60	1.60	1.60	7.0E-02	3.36	3.40	0.30	7.0E-03	13,922
Sep-19	0.42	1.04	1.46	1.46	1.46	6.4E-02	3.52	2.50	0.27	6.4E-03	12,687
Oct-19	0.11	0.26	0.36	0.36	0.36	1.6E-02	1.04	2.70	6.7E-02	1.6E-03	3,155
Nov-19	3.7E-02	9.1E-02	0.13	0.13	0.13	6.0E-03	0.40	0.50	2.4E-02	5.6E-04	1,108
Dec-19	4.9E-02	0.12	0.17	0.17	0.17	7.0E-03	0.62	1.30	3.1E-02	7.4E-04	1,463
Jan-20	--	--	--	--	--	--	--	--	--	--	--
Feb-20	1.4E-04	3.5E-04	5.0E-04	5.0E-04	5.0E-04	--	3.0E-03	0.10	9.2E-05	2.2E-06	4.30
Mar-20	5.5E-03	1.4E-02	1.9E-02	1.9E-02	1.9E-02	1.0E-03	8.1E-02	0.40	3.5E-03	8.3E-05	165
Apr-20	1.5E-02	3.8E-02	5.3E-02	5.3E-02	5.3E-02	2.0E-03	0.15	0.10	9.9E-03	2.3E-04	462
May-20	0.17	0.43	0.60	0.60	0.60	2.6E-02	1.37	1.20	0.11	2.6E-03	5,236
Jun-20	0.37	0.91	1.29	1.29	1.29	5.6E-02	2.92	2.60	0.24	5.6E-03	11,164
Jul-20	0.52	1.28	1.80	1.80	1.80	7.9E-02	3.78	2.80	0.33	7.9E-03	15,662
Aug-20	0.36	0.89	1.25	1.25	1.25	5.5E-02	2.68	2.20	0.23	5.5E-03	10,847
Sep-20	0.25	0.60	0.85	0.85	0.85	3.7E-02	1.86	1.40	0.16	3.7E-03	7,367
Oct-20	0.17	0.43	0.60	0.60	0.60	2.6E-02	1.36	1.10	0.11	2.6E-03	5,228
Nov-20	4.1E-02	0.10	0.14	0.14	0.14	6.0E-03	0.44	1.00	2.6E-02	6.2E-04	1,228
Dec-20	--	--	--	--	--	--	--	--	--	--	--
Jan-21	8.4E-05	2.1E-04	2.9E-04	2.9E-04	2.9E-04	--	2.0E-03	0.10	5.4E-05	1.3E-06	2.51
Feb-21	--	--	--	--	--	--	--	--	--	--	--
Mar-21	--	--	--	--	--	--	--	--	--	--	--
Apr-21	0.13	0.31	0.44	0.44	0.44	1.9E-02	1.12	1.40	8.1E-02	1.9E-03	3,792
May-21	0.16	0.39	0.55	0.55	0.55	2.4E-02	1.44	1.10	0.10	2.4E-03	4,761
Jun-21	0.25	0.60	0.85	0.85	0.85	3.7E-02	2.06	2.20	0.16	3.7E-03	7,392
Jul-21	0.22	0.54	0.77	0.77	0.77	3.4E-02	1.66	1.30	0.14	3.4E-03	6,662
Aug-21	0.20	0.49	0.69	0.69	0.69	3.0E-02	1.60	1.90	0.13	3.0E-03	5,953
Sep-21	8.0E-02	0.20	0.28	0.28	0.28	1.2E-02	0.63	0.50	5.1E-02	1.2E-03	2,407
Oct-21	0.19	0.47	0.66	0.66	0.66	2.9E-02	1.53	1.20	0.12	2.9E-03	5,732
Nov-21	--	--	--	--	--	--	--	--	--	--	--
Dec-21	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--
Feb-22	7.6E-05	1.9E-04	2.6E-04	2.6E-04	2.6E-04	--	1.0E-03	0.10	4.9E-05	1.2E-06	2.28
Mar-22	--	--	--	--	--	--	--	--	--	--	--
Apr-22	1.1E-02	2.8E-02	3.9E-02	3.9E-02	3.9E-02	2.0E-03	0.11	0.11	7.3E-03	1.7E-04	340
May-22	0.17	0.41	0.58	0.58	0.58	2.5E-02	1.48	0.81	0.11	2.5E-03	5,026
Jun-22	0.45	1.10	1.55	1.55	1.55	6.8E-02	3.60	1.36	0.29	6.8E-03	13,454
Jul-22	0.65	1.59	2.23	2.23	2.23	9.8E-02	4.78	1.90	0.41	9.8E-03	19,391
Aug-22	0.60	1.46	2.05	2.05	2.05	9.0E-02	4.48	1.90	0.38	9.0E-03	17,835
Sep-22	0.33	0.82	1.15	1.15	1.15	5.0E-02	2.78	1.46	0.21	5.0E-03	9,970
Oct-22	2.4E-02	6.0E-02	8.4E-02	8.4E-02	8.4E-02	4.0E-03	0.26	0.20	1.6E-02	3.7E-04	728
Nov-22	2.5E-02	6.1E-02	8.6E-02	8.6E-02	8.6E-02	4.0E-03	0.30	0.31	1.6E-02	3.8E-04	747
Dec-22	1.0E-01	0.24	0.34	0.34	0.34	1.5E-02	1.16	1.02	6.4E-02	1.5E-03	2,987

1. Excluding SO_2, NO_X, CO, and CO_2e, 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 site data as reported to the U.S. EPA in the Clean Air Markets Program Data (CAMPD) system. Baseline Emissions of CO from site CEMS data.

3. Baseline emissions of CO_2e are calculated using the historical CO_2 emissions data, 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 Turbines (tons/month)

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
	Combustion Turbine Nos. 1 - 4										
Mar-14	0.16	0.39	0.55	0.55	0.55	2.4E-02	2.13	12	0.10	2.4E-03	4,778
Apr-14	6.2E-02	0.15	0.21	0.21	0.21	1.0E-02	0.62	1.70	3.9E-02	9.3E-04	1,847
May-14	0.35	0.86	1.21	1.21	1.21	5.3E-02	2.69	4.90	0.22	5.3E-03	10,502
Jun-14	0.43	1.04	1.47	1.47	1.47	6.4E-02	2.90	4.50	0.27	6.4E-03	12,769
Jul-14	0.72	1.77	2.50	2.50	2.50	0.11	4.63	6.40	0.46	1.1E-02	21,673
Aug-14	0.84	2.06	2.90	2.90	2.90	0.13	5.87	7.40	0.54	1.3E-02	25,208
Sep-14	0.35	0.85	1.19	1.19	1.19	5.2E-02	2.42	3.90	0.22	5.2E-03	10,348
Oct-14	0.73	1.80	2.53	2.53	2.53	0.11	5.06	4.90	0.47	1.1E-02	21,978
Nov-14	0.16	0.40	0.57	0.57	0.57	2.6E-02	1.80	2.90	0.11	2.5E-03	4,930
Dec-14	2.9E-02	7.1E-02	1.0E-01	1.0E-01	1.0E-01	5.0E-03	0.34	0.80	1.9E-02	4.4E-04	867
Jan-15	3.0E-02	7.4E-02	0.10	0.10	0.10	5.0E-03	0.44	0.80	1.9E-02	4.6E-04	903
Feb-15	4.4E-03	1.1E-02	1.5E-02	1.5E-02	1.5E-02	1.0E-03	7.1E-02	0.80	2.8E-03	6.6E-05	132
Mar-15	4.8E-03	1.2E-02	1.6E-02	1.6E-02	1.6E-02	1.0E-03	6.0E-02	0.20	3.0E-03	7.2E-05	142
Apr-15	0.14	0.34	0.47	0.47	0.47	2.1E-02	1.02	0.80	8.8E-02	2.1E-03	4,118
May-15	1.06	2.59	3.65	3.65	3.65	0.16	7.82	8.70	0.68	1.6E-02	31,699
Jun-15	0.92	2.25	3.16	3.16	3.16	0.14	6.50	7.60	0.59	1.4E-02	27,484
Jul-15	1.47	3.60	5.06	5.06	5.06	0.22	10	12	0.94	2.2E-02	43,977
Aug-15	1.11	2.71	3.82	3.82	3.82	0.17	7.84	9.90	0.71	1.7E-02	33,191
Sep-15	0.91	2.23	3.14	3.14	3.14	0.14	6.55	6.70	0.58	1.4E-02	27,241
Oct-15	0.67	1.64	2.31	2.31	2.31	0.10	5.56	4.50	0.43	1.0E-02	20,075
Nov-15	0.38	0.92	1.30	1.30	1.30	5.7E-02	2.68	1.90	0.24	5.7E-03	11,267
Dec-15	--	--	--	--	--	--	--	--	--	--	--
Jan-16	1.7E-02	4.3E-02	6.0E-02	6.0E-02	6.0E-02	3.0E-03	0.24	0.30	1.1E-02	2.6E-04	521
Feb-16	7.9E-02	0.19	0.27	0.27	0.27	1.2E-02	0.82	1.40	5.0E-02	1.2E-03	2,360
Mar-16	0.64	1.58	2.22	2.22	2.22	9.8E-02	5.47	3.90	0.41	9.7E-03	19,279
Apr-16	0.90	2.21	3.11	3.11	3.11	0.14	7.45	5.50	0.58	1.4E-02	27,036
May-16	2.24	5.47	7.71	7.71	7.71	0.34	18	14	1.43	3.4E-02	66,940
Jun-16	2.25	5.51	7.76	7.76	7.76	0.34	16	14	1.44	3.4E-02	67,393
Jul-16	2.27	5.56	7.83	7.83	7.83	0.34	15	15	1.45	3.4E-02	68,019
Aug-16	2.26	5.54	7.80	7.80	7.80	0.34	15	14	1.45	3.4E-02	67,718
Sep-16	1.56	3.82	5.38	5.38	5.38	0.24	11	12	1.00	2.4E-02	46,703
Oct-16	4.2E-02	0.10	0.14	0.14	0.14	6.0E-03	0.34	0.30	2.7E-02	6.3E-04	1,257
Nov-16	0.12	0.30	0.42	0.42	0.42	1.9E-02	1.31	1.80	7.9E-02	1.9E-03	3,683
Dec-16	0.31	0.76	1.07	1.07	1.07	4.7E-02	3.25	4.10	0.20	4.7E-03	9,313
Jan-17	0.13	0.32	0.45	0.45	0.45	2.0E-02	1.32	1.70	8.4E-02	2.0E-03	3,938
Feb-17	6.5E-03	1.6E-02	2.2E-02	2.2E-02	2.2E-02	1.0E-03	7.6E-02	0.10	4.1E-03	9.8E-05	194
Mar-17	6.5E-02	0.16	0.23	0.23	0.23	9.0E-03	0.68	0.70	4.2E-02	9.9E-04	1,956
Apr-17	0.50	1.24	1.74	1.74	1.74	7.6E-02	4.19	4.00	0.32	7.6E-03	15,115
May-17	0.97	2.37	3.34	3.34	3.34	0.15	7.66	7.30	0.62	1.5E-02	28,975
Jun-17	0.50	1.22	1.72	1.72	1.72	7.5E-02	3.54	3.90	0.32	7.5E-03	14,917
Jul-17	1.47	3.60	5.07	5.07	5.07	0.22	10	12	0.94	2.2E-02	44,073
Aug-17	1.17	2.85	4.02	4.02	4.02	0.18	8.53	11	0.75	1.8E-02	34,913
Sep-17	0.77	1.88	2.65	2.65	2.65	0.12	5.76	6.60	0.49	1.2E-02	22,983
Oct-17	0.26	0.63	0.88	0.88	0.88	3.8E-02	2.23	3.50	0.16	3.9E-03	7,669
Nov-17	0.22	0.54	0.77	0.77	0.77	3.3E-02	1.97	2.50	0.14	3.4E-03	6,652
Dec-17	1.0E-02	2.5E-02	3.5E-02	3.5E-02	3.5E-02	2.0E-03	0.12	0.40	6.5E-03	1.5E-04	304
Jan-18	0.20	0.48	0.68	0.68	0.68	3.0E-02	2.05	2.50	0.13	3.0E-03	5,912
Feb-18	--	--	--	--	--	--	--	--	--	--	--
Mar-18	8.9E-03	2.2E-02	3.1E-02	3.1E-02	3.1E-02	1.0E-03	0.10	0.10	5.7E-03	1.3E-04	267
Apr-18	4.0E-02	9.8E-02	0.14	0.14	0.14	6.0E-03	0.43	1.00	2.5E-02	6.0E-04	1,194
May-18	1.23	3.00	4.23	4.23	4.23	0.19	9.87	10	0.78	1.9E-02	36,722
Jun-18	1.28	3.14	4.42	4.42	4.42	0.19	9.63	13	0.82	1.9E-02	38,369
Jul-18	1.63	3.99	5.62	5.62	5.62	0.25	12	12	1.04	2.5E-02	48,800
Aug-18	1.68	4.12	5.81	5.81	5.81	0.25	12	13	1.08	2.5E-02	50,419
Sep-18	2.16	5.29	7.46	7.46	7.46	0.33	16	14	1.38	3.3E-02	64,745
Oct-18	0.22	0.53	0.74	0.74	0.74	3.3E-02	1.75	2.30	0.14	3.3E-03	6,467
Nov-18	4.3E-02	0.10	0.15	0.15	0.15	6.0E-03	0.54	1.20	2.7E-02	6.4E-04	1,275
Dec-18	0.15	0.37	0.52	0.52	0.52	2.2E-02	1.95	3.40	9.6E-02	2.3E-03	4,502

Table B-10. 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-19	0.16	0.40	0.56	0.56	0.56	2.5E-02	1.82	2.30	0.10	2.5E-03	4,893
Feb-19	6.6E-02	0.16	0.23	0.23	0.23	1.0E-02	0.65	1.30	4.2E-02	1.0E-03	1,973
Mar-19	0.17	0.42	0.60	0.60	0.60	2.7E-02	1.92	3.00	0.11	2.6E-03	5,189
Apr-19	0.38	0.92	1.30	1.30	1.30	5.7E-02	3.00	2.90	0.24	5.7E-03	11,249
May-19	1.15	2.81	3.95	3.95	3.95	0.17	8.75	10	0.73	1.7E-02	34,324
Jun-19	0.74	1.81	2.55	2.55	2.55	0.11	5.59	7.00	0.47	1.1E-02	22,129
Jul-19	1.66	4.08	5.74	5.74	5.74	0.25	12	12	1.06	2.5E-02	49,856
Aug-19	1.94	4.76	6.71	6.71	6.71	0.29	14	13	1.24	2.9E-02	58,239
Sep-19	1.75	4.28	6.03	6.03	6.03	0.26	13	11	1.12	2.6E-02	52,373
Oct-19	0.37	0.90	1.27	1.27	1.27	5.6E-02	3.04	6.40	0.23	5.5E-03	10,993
Nov-19	0.12	0.30	0.43	0.43	0.43	1.9E-02	1.40	4.60	8.0E-02	1.9E-03	3,725
Dec-19	0.17	0.42	0.59	0.59	0.59	2.6E-02	2.00	3.70	0.11	2.6E-03	5,150
Jan-20	1.6E-02	4.0E-02	5.6E-02	5.6E-02	5.6E-02	2.0E-03	0.11	0.10	1.0E-02	2.4E-04	484
Feb-20	2.9E-04	7.2E-04	1.0E-03	1.0E-03	1.0E-03	--	7.0E-03	0.20	1.9E-04	4.4E-06	8.81
Mar-20	3.2E-02	7.7E-02	0.11	0.11	0.11	5.0E-03	0.35	0.80	2.0E-02	4.8E-04	945
Apr-20	9.8E-02	0.24	0.34	0.34	0.34	1.4E-02	0.79	0.60	6.3E-02	1.5E-03	2,942
May-20	0.80	1.97	2.77	2.77	2.77	0.12	5.99	6.30	0.51	1.2E-02	24,084
Jun-20	1.36	3.33	4.69	4.69	4.69	0.21	9.92	12	0.87	2.1E-02	40,709
Jul-20	1.96	4.80	6.76	6.76	6.76	0.30	13	12	1.25	3.0E-02	58,686
Aug-20	1.81	4.44	6.25	6.25	6.25	0.27	13	9.80	1.16	2.7E-02	54,274
Sep-20	0.82	2.00	2.82	2.82	2.82	0.12	5.87	4.90	0.52	1.2E-02	24,487
Oct-20	0.28	0.67	0.95	0.95	0.95	4.1E-02	2.14	1.80	0.18	4.2E-03	8,243
Nov-20	0.14	0.33	0.47	0.47	0.47	2.0E-02	1.27	1.70	8.7E-02	2.0E-03	4,063
Dec-20	3.2E-02	7.7E-02	0.11	0.11	0.11	5.0E-03	0.37	0.90	2.0E-02	4.8E-04	945
Jan-21	8.2E-03	2.0E-02	2.8E-02	2.8E-02	2.8E-02	1.0E-03	0.15	0.90	5.2E-03	1.2E-04	244
Feb-21	9.8E-03	2.4E-02	3.4E-02	3.4E-02	3.4E-02	1.0E-03	0.14	0.30	6.3E-03	1.5E-04	294
Mar-21	0.10	0.25	0.35	0.35	0.35	1.6E-02	1.26	3.20	6.5E-02	1.5E-03	3,041
Apr-21	0.38	0.94	1.32	1.32	1.32	5.8E-02	3.20	3.40	0.25	5.8E-03	11,493
May-21	0.64	1.56	2.19	2.19	2.19	9.6E-02	5.02	4.20	0.41	9.6E-03	19,046
Jun-21	1.10	2.68	3.78	3.78	3.78	0.17	8.07	6.80	0.70	1.7E-02	32,803
Jul-21	0.88	2.16	3.04	3.04	3.04	0.13	6.13	5.70	0.56	1.3E-02	26,419
Aug-21	0.83	2.04	2.88	2.88	2.88	0.13	6.65	6.40	0.53	1.3E-02	24,996
Sep-21	0.27	0.65	0.91	0.91	0.91	4.0E-02	2.26	2.00	0.17	4.0E-03	7,945
Oct-21	0.37	0.90	1.27	1.27	1.27	5.5E-02	2.97	2.10	0.23	5.5E-03	10,996
Nov-21	3.5E-02	8.5E-02	0.12	0.12	0.12	5.0E-03	0.53	1.10	2.2E-02	5.3E-04	1,045
Dec-21	--	--	--	--	--	--	--	--	--	--	--
Jan-22	--	--	--	--	--	--	--	--	--	--	--
Feb-22	1.6E-04	3.8E-04	5.4E-04	5.4E-04	5.4E-04	--	3.0E-03	0.20	9.9E-05	2.3E-06	4.66
Mar-22	--	--	--	--	--	--	--	--	--	--	--
Apr-22	5.7E-02	0.14	0.20	0.20	0.20	9.0E-03	0.59	0.64	3.7E-02	8.6E-04	1,710
May-22	0.87	2.13	3.00	3.00	3.00	0.13	7.58	3.92	0.56	1.3E-02	26,053
Jun-22	1.92	4.71	6.63	6.63	6.63	0.29	15	6.68	1.23	2.9E-02	57,584
Jul-22	2.69	6.59	9.28	9.28	9.28	0.41	20	8.56	1.72	4.1E-02	80,582
Aug-22	2.44	5.96	8.40	8.40	8.40	0.37	18	9.12	1.56	3.7E-02	72,923
Sep-22	1.47	3.59	5.06	5.06	5.06	0.22	12	6.18	0.94	2.2E-02	43,921
Oct-22	5.4E-02	0.13	0.18	0.18	0.18	9.0E-03	0.60	0.44	3.4E-02	8.1E-04	1,604
Nov-22	9.0E-02	0.22	0.31	0.31	0.31	1.4E-02	1.05	0.83	5.7E-02	1.4E-03	2,693
Dec-22	0.25	0.61	0.86	0.86	0.86	3.8E-02	2.94	2.44	0.16	3.8E-03	7,448

Table B-11. Selection of Baseline (tpy)[1]

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
			Combustion Turbine Nos. 1 - 4 Baseline Emissions										
Mar-14	-	Feb-16	5.31	13.00	18.31	18.31	18.31	0.81	39.05	52.35	3.39	0.08	159,004
Apr-14	-	Mar-16	5.55	13.59	19.14	19.14	19.14	0.84	40.72	48.30	3.55	0.08	166,255
May-14	-	Apr-16	5.97	14.62	20.59	20.59	20.59	0.90	44.13	50.20	3.82	0.09	178,849
Jun-14	-	May-16	6.91	16.93	23.84	23.84	23.84	1.05	51.66	54.75	4.42	0.10	207,068
Jul-14	-	Jun-16	7.83	19.16	26.99	26.99	26.99	1.18	58.23	59.30	5.00	0.12	234,380
Aug-14	-	Jul-16	8.60	21.06	29.66	29.66	29.66	1.30	63.56	63.55	5.50	0.13	257,553
Sep-14	-	Aug-16	9.31	22.79	32.10	32.10	32.10	1.41	68.19	67.00	5.95	0.14	278,808
Oct-14	-	Sep-16	9.92	24.28	34.20	34.20	34.20	1.50	72.71	70.90	6.34	0.15	296,985
Nov-14	-	Oct-16	9.57	23.43	33.00	33.00	33.00	1.45	70.35	68.60	6.12	0.14	286,625
Dec-14	-	Nov-16	9.55	23.38	32.93	32.93	32.93	1.44	70.10	68.05	6.11	0.14	286,001
Jan-15	-	Dec-16	9.69	23.73	33.42	33.42	33.42	1.47	71.56	69.70	6.20	0.15	290,224
Feb-15	-	Jan-17	9.74	23.85	33.59	33.59	33.59	1.47	72.00	70.15	6.23	0.15	291,742
Mar-15	-	Feb-17	9.74	23.85	33.60	33.60	33.60	1.47	72.00	69.80	6.23	0.15	291,773
Apr-15	-	Mar-17	9.77	23.93	33.70	33.70	33.70	1.48	72.31	70.05	6.25	0.15	292,680
May-15	-	Apr-17	9.96	24.38	34.33	34.33	34.33	1.50	73.90	71.65	6.37	0.15	298,178
Jun-15	-	May-17	9.91	24.27	34.18	34.18	34.18	1.50	73.81	70.95	6.34	0.15	296,816
Jul-15	-	Jun-17	9.70	23.75	33.45	33.45	33.45	1.46	72.33	69.10	6.20	0.15	290,533
Aug-15	-	Jul-17	9.70	23.76	33.46	33.46	33.46	1.46	72.55	69.10	6.20	0.15	290,581
Sep-15	-	Aug-17	9.73	23.83	33.56	33.56	33.56	1.47	72.90	69.75	6.22	0.15	291,441
Oct-15	-	Sep-17	9.66	23.65	33.31	33.31	33.31	1.46	72.50	69.70	6.18	0.15	289,312
Nov-15	-	Oct-17	9.45	23.15	32.60	32.60	32.60	1.43	70.84	69.20	6.04	0.14	283,110
Dec-15	-	Nov-17	9.38	22.96	32.33	32.33	32.33	1.41	70.48	69.50	5.99	0.14	280,802
Jan-16	-	Dec-17	9.38	22.97	32.35	32.35	32.35	1.42	70.54	69.70	6.00	0.14	280,954
Feb-16	-	Jan-18	9.47	23.19	32.66	32.66	32.66	1.43	71.45	70.80	6.06	0.14	283,650
Mar-16	-	Feb-18	9.43	23.09	32.53	32.53	32.53	1.42	71.04	70.10	6.03	0.14	282,470
Apr-16	-	Mar-18	9.12	22.32	31.43	31.43	31.43	1.37	68.36	68.20	5.83	0.14	272,964
May-16	-	Apr-18	8.68	21.26	29.94	29.94	29.94	1.31	64.84	65.95	5.55	0.13	260,043
Jun-16	-	May-18	8.18	20.02	28.20	28.20	28.20	1.23	60.91	63.95	5.23	0.12	244,935
Jul-16	-	Jun-18	7.69	18.84	26.53	26.53	26.53	1.16	57.70	63.50	4.92	0.12	230,423
Aug-16	-	Jul-18	7.37	18.05	25.43	25.43	25.43	1.11	55.85	62.10	4.71	0.11	220,813
Sep-16	-	Aug-18	7.08	17.35	24.43	24.43	24.43	1.07	54.35	61.25	4.53	0.11	212,164
Oct-16	-	Sep-18	7.39	18.08	25.47	25.47	25.47	1.11	56.52	62.35	4.72	0.11	221,185
Nov-16	-	Oct-18	7.47	18.30	25.77	25.77	25.77	1.13	57.23	63.35	4.78	0.11	223,790
Dec-16	-	Nov-18	7.43	18.20	25.63	25.63	25.63	1.12	56.84	63.05	4.75	0.11	222,586

Table B-11. Selection of Baseline (tpy)[1]

			Combustion Turbine Nos. 1 - 4 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
Jan-17	-	Dec-18	7.35	18.00	25.35	25.35	25.35	1.11	56.19	62.70	4.70	0.11	220,180
Feb-17	-	Jan-19	7.37	18.04	25.41	25.41	25.41	1.11	56.45	63.00	4.71	0.11	220,657
Mar-17	-	Feb-19	7.40	18.11	25.51	25.51	25.51	1.12	56.73	63.60	4.73	0.11	221,547
Apr-17	-	Mar-19	7.45	18.24	25.70	25.70	25.70	1.12	57.35	64.75	4.76	0.11	223,163
May-17	-	Apr-19	7.39	18.09	25.47	25.47	25.47	1.12	56.76	64.20	4.72	0.11	221,230
Jun-17	-	May-19	7.48	18.31	25.78	25.78	25.78	1.13	57.31	65.60	4.78	0.11	223,905
Jul-17	-	Jun-19	7.60	18.60	26.20	26.20	26.20	1.15	58.33	67.15	4.86	0.11	227,511
Aug-17	-	Jul-19	7.69	18.84	26.53	26.53	26.53	1.16	59.06	67.50	4.92	0.12	230,403
Sep-17	-	Aug-19	8.08	19.79	27.87	27.87	27.87	1.22	61.64	68.15	5.17	0.12	242,066
Oct-17	-	Sep-19	8.57	20.99	29.57	29.57	29.57	1.29	65.39	70.45	5.48	0.13	256,761
Nov-17	-	Oct-19	8.63	21.13	29.76	29.76	29.76	1.30	65.80	71.90	5.52	0.13	258,423
Dec-17	-	Nov-19	8.58	21.01	29.59	29.59	29.59	1.30	65.51	72.95	5.49	0.13	256,960
Jan-18	-	Dec-19	8.66	21.21	29.87	29.87	29.87	1.31	66.45	74.60	5.54	0.13	259,382
Feb-18	-	Jan-20	8.57	20.98	29.55	29.55	29.55	1.29	65.48	73.40	5.48	0.13	256,668
Mar-18	-	Feb-20	8.57	20.98	29.56	29.56	29.56	1.29	65.49	73.50	5.48	0.13	256,673
Apr-18	-	Mar-20	8.58	21.01	29.59	29.59	29.59	1.30	65.61	73.85	5.49	0.13	257,011
May-18	-	Apr-20	8.61	21.08	29.69	29.69	29.69	1.30	65.79	73.65	5.51	0.13	257,885
Jun-18	-	May-20	8.40	20.57	28.97	28.97	28.97	1.27	63.85	71.80	5.37	0.13	251,566
Jul-18	-	Jun-20	8.44	20.66	29.10	29.10	29.10	1.27	64.00	71.30	5.40	0.13	252,737
Aug-18	-	Jul-20	8.60	21.07	29.67	29.67	29.67	1.30	64.96	71.35	5.50	0.13	257,680
Sep-18	-	Aug-20	8.67	21.22	29.89	29.89	29.89	1.31	65.19	69.95	5.54	0.13	259,607
Oct-18	-	Sep-20	8.00	19.58	27.58	27.58	27.58	1.21	60.23	65.45	5.11	0.12	239,478
Nov-18	-	Oct-20	8.03	19.65	27.68	27.68	27.68	1.21	60.43	65.20	5.13	0.12	240,366
Dec-18	-	Nov-20	8.07	19.77	27.84	27.84	27.84	1.22	60.79	65.45	5.16	0.12	241,760
Jan-19	-	Dec-20	8.01	19.62	27.63	27.63	27.63	1.21	60.00	64.20	5.12	0.12	239,982
Feb-19	-	Jan-21	7.94	19.43	27.37	27.37	27.37	1.20	59.17	63.50	5.07	0.12	237,658
Mar-19	-	Feb-21	7.91	19.36	27.27	27.27	27.27	1.19	58.91	63.00	5.06	0.12	236,818
Apr-19	-	Mar-21	7.87	19.27	27.15	27.15	27.15	1.19	58.58	63.10	5.03	0.12	235,745
May-19	-	Apr-21	7.88	19.28	27.16	27.16	27.16	1.19	58.68	63.35	5.04	0.12	235,866
Jun-19	-	May-21	7.62	18.66	26.28	26.28	26.28	1.15	56.81	60.40	4.87	0.12	228,227
Jul-19	-	Jun-21	7.80	19.10	26.89	26.89	26.89	1.18	58.05	60.30	4.99	0.12	233,564
Aug-19	-	Jul-21	7.41	18.14	25.55	25.55	25.55	1.12	55.14	56.95	4.74	0.11	221,846
Sep-19	-	Aug-21	6.85	16.78	23.63	23.63	23.63	1.03	51.63	53.90	4.38	0.10	205,224
Oct-19	-	Sep-21	6.11	14.96	21.07	21.07	21.07	0.92	46.12	49.30	3.91	0.09	183,010
Nov-19	-	Oct-21	6.11	14.96	21.07	21.07	21.07	0.92	46.09	47.15	3.91	0.09	183,011
Dec-19	-	Nov-21	6.07	14.85	20.92	20.92	20.92	0.91	45.65	45.40	3.88	0.09	181,672

Table B-11. Selection of Baseline (tpy)[1]

			Combustion Turbine Nos. 1 - 4 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**
Jan-20	-	Dec-21	5.98	14.64	20.62	20.62	20.62	0.90	44.65	43.55	3.82	0.09	179,096
Feb-20	-	Jan-22	5.97	14.62	20.59	20.59	20.59	0.90	44.59	43.50	3.82	0.09	178,855
Mar-20	-	Feb-22	5.97	14.62	20.59	20.59	20.59	0.90	44.59	43.50	3.82	0.09	178,853
Apr-20	-	Mar-22	5.96	14.58	20.54	20.54	20.54	0.90	44.42	43.10	3.81	0.09	178,380
May-20	-	Apr-22	5.94	14.53	20.47	20.47	20.47	0.90	44.31	43.12	3.80	0.09	177,764
Jun-20	-	May-22	5.97	14.61	20.58	20.58	20.58	0.90	45.11	41.93	3.82	0.09	178,749
Jul-20	-	Jun-22	6.25	15.30	21.55	21.55	21.55	0.94	47.78	39.42	4.00	0.09	187,186
Aug-20	-	Jul-22	6.62	16.20	22.81	22.81	22.81	1.00	50.94	37.60	4.23	0.10	198,134
Sep-20	-	Aug-22	6.93	16.96	23.89	23.89	23.89	1.05	53.79	37.26	4.43	0.10	207,459
Oct-20	-	Sep-22	7.25	17.76	25.01	25.01	25.01	1.09	56.73	37.90	4.64	0.11	217,176
Nov-20	-	Oct-22	7.14	17.48	24.63	24.63	24.63	1.08	55.95	37.22	4.57	0.11	213,856
Dec-20	-	Nov-22	7.12	17.43	24.55	24.55	24.55	1.08	55.84	36.79	4.55	0.11	213,171
Jan-21	-	Dec-22	7.23	17.69	24.92	24.92	24.92	1.09	57.13	37.56	4.62	0.11	216,423
Max Annual Baseline Emissions:			**9.96**	**24.38**	**34.33**	**34.33**	**34.33**	**1.50**	**73.90**	**74.60**	**6.37**	**0.15**	**298,178**
		Period Start:	**May-15**	**May-15**	**May-15**	**May-15**	**May-15**	**May-15**	**May-15**	**Jan-18**	**May-15**	**May-15**	**May-15**
		Period End:	**Apr-17**	**Apr-17**	**Apr-17**	**Apr-17**	**Apr-17**	**Apr-17**	**Apr-17**	**Dec-19**	**Apr-17**	**Apr-17**	**Apr-17**

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.

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table B-12. Projected Actual Criteria Pollutant Emissions from Turbine No. 1 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	6.00E-04	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table B-13. Projected Actual Criteria Pollutant Emissions from Turbine No. 1 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-14. Projected Actual Emissions from Turbine No. 1 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.

2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.

3. Projected Actual Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Projected Actual Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.

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-15. Projected Actual Criteria Pollutant Emissions from Combustion Turbine No. 1

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table B-16. Projected Actual Criteria Pollutant Emissions from Turbine No. 2 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	6.00E-04	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table B-17. Projected Actual Criteria Pollutant Emissions from Turbine No. 2 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-18. Projected Actual Emissions from Turbine No. 2 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Emissions[3] (lb/hr)	Emissions[3] (tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.

2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.

3. Projected Actual Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Projected Actual Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.

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-19. Projected Actual Criteria Pollutant Emissions from Combustion Turbine No. 2

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table B-20. Projected Actual Criteria Pollutant Emissions from Turbine No. 3 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	6.00E-04	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table B-21. Projected Actual Criteria Pollutant Emissions from Turbine No. 3 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-22. Projected Actual Emissions from Turbine No. 3 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.

2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.

3. Projected Actual Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Projected Actual Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.

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-23. Projected Actual Criteria Pollutant Emissions from Combustion Turbine No. 3

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table B-24. Projected Actual Criteria Pollutant Emissions from Turbine No. 4 Natural Gas Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	6.00E-04	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table B-3 for details on emission factors for turbines combusting natural gas.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table B-25. Projected Actual Criteria Pollutant Emissions from Turbine No. 4 Fuel Oil Combustion

Pollutant	Emission Factor[1] (lb/MMBtu)	Hourly Emissions[2] (lb/hr)	Annual Emissions[3] (tpy)
SO_2	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table B-4 for details on emission factors for turbines combusting ULSD.
2. Projected Actual Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Maximum Heat Input Capacity (MMBtu/hr)
3. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table B-26. Projected Actual Emissions from Turbine No. 4 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.
2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.
3. Projected Actual Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Projected Actual Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.
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-27. Projected Actual Criteria Pollutant Emissions from Combustion Turbine No. 4

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Table B-28. Projected Actual Criteria Pollutant 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	1.79	1.79	1.79	1.79	7.17
NO_X	156.82	156.82	156.82	156.82	627.29
CO	97.08	97.08	97.08	97.08	388.32
Total PM	35.53	35.53	35.53	35.53	142.13
Filterable PM	10.67	10.67	10.67	10.67	42.68
Condensable PM	24.86	24.86	24.86	24.86	99.45
Total PM_{10}	35.53	35.53	35.53	35.53	142.13
Total $PM_{2.5}$	35.53	35.53	35.53	35.53	142.13
VOC	12.59	12.59	12.59	12.59	50.36
Lead	4.3E-03	4.3E-03	4.3E-03	4.3E-03	1.7E-02
Sulfuric Acid Mist (H_2SO_4)	0.18	0.18	0.18	0.18	0.72
CO_2e	313,253	313,253	313,253	313,253	1,253,010

New Fire Pump Operating Parameters - Fuel Oil Combustion

Nameplate	455	hp
	388	kW
Fuel Consumption	23.1	gal/hr
Heat Input Capacity	3.23	MMBtu/hr
Operating Hours	500	hrs/yr

Table B-29. New Fire Pump Emissions

Pollutant	Emission Factor	Emission Factor Unit and Reference	Hourly Emissions[1] (lb/hr)	Annual Emissions[2] (tpy)
SO_2	2.05E-03	(lb/hp-hr), Note 3	0.93	0.23
NO_X	3.58	(g/kW-hr), Note 4	3.06	0.77
CO	2.17	(g/kW-hr), Note 4	1.86	0.46
Total PM	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
Filterable PM	4.61E-02	(g/kW-hr), Note 4,5	0.039	0.010
Condensable PM	2.99E-02	(g/kW-hr), Note 4,5	0.026	0.006
Total PM_{10}	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
Total $PM_{2.5}$	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
VOC	1.30E-01	(g/kW-hr), Note 4	0.11	0.028
Sulfuric Acid Mist (H_2SO_4)	2.05E-04	(lb/hp-hr), Note 3	0.093	0.023
GHGs				
CO_2	163.05	(lb/MMBtu), Note 6	527.31	131.83
CH_4	6.61E-03	(lb/MMBtu), Note 6	2.14E-02	5.35E-03
N_2O	1.32E-03	(lb/MMBtu), Note 6	4.28E-03	1.07E-03
CO_2e	163.61	(lb/MMBtu), Note 7	529.12	132.28

1. Projected Actual Emissions (lb/hr) = Emission Factor * Nameplate Capacity, converted from grams to pounds if necessary
2. Projected Actual Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
3. SO_2 emission factor from AP-42 Section 3.3, Gasoline And Diesel Industrial Engines, Table 3.3-1.
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.
4. Emissions data from Caterpillar.

5. Emission factors for filterable and condensable PM are estimated from AP-42 Section 1.3, Fuel Oil Combustion, Table 3.1-2a (April 2000).

6. 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.

7. 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

New Fuel Oil Storage Tanks Operating Parameters (2 New Tanks)

Storage Components	Ultra Low-Sulfur Diesel	
Max Daily Operating	24	hours/day
Annual Operating Hours	8,760	hours/year
Tank Type	VFRT	
Tank Capacity (each)	1,580,000	gallons
Tank Annual Throughput[1] (each)	8,775,000	gallons/yr

Table B-30. New Fuel Oil Storage Tanks Emissions

Pollutant	Total Losses (lb)	Potential Annual Emissions (tpy)
Fuel Oil Tank No. 2		
VOC	944.46	0.47
Fuel Oil Tank No. 3		
VOC	944.46	0.47

1. Tank Annual Throughput (gal/yr, each) = Sum for Combustion Turbine Nos. 1 - 4 on Fuel Oil { Heat Input Capacity (MMBtu/hr) / 0.140 (MMBtu/gal) * Hours of Operation (hr/yr) } / 2

Fixed-Roof Tank Emissions - Monthly

Reporting Year	2023

Based on AP-42 (Nov 2019), Section 7.1.3.1.
Tool Last Updated: Mar 2021
Click Here to Go Back to Cover Page

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Tank ID	Enter only Tank ID in this tab.			New Fuel Oil Tank No. 2
Tank Name	Text Description of Tank Name	TK_{name}		
Actual Location		Loc_{Act}		Box Springs, GA
Location for Calculation Purposes		Loc_{Calc}		Columbus, GA
Tank/Roof Type		TK_{roof}		VFR - Cone
Normal Capacity		Cap	gal	1,580,000
Diameter		D	ft	82
Shell Height or Length		H_S	ft	40
Effective Diameter	= $((H_S * D) / (\pi/4))^{0.5}$ {horiz. tanks only, Eqn. 1-14} = D {all other fixed roof tanks}	D_E	ft	82.0
Effective Height	= π/4 * D {horiz. tanks only, Eqn. 1-15} = H_S -1 {all other fixed roof tanks}	H_E	ft	39.0
External Shell Color		SC_{ext}		Green/Dark
External Shell Paint Condition		PC_{Shell}		New
Roof Color/Shade		RC		Green/Dark
Roof Paint Condition		PC_{Roof}		New
Tank Shell Solar Absorbance		α_{Shell}		0.89
Tank Roof Paint Solar Absorbance		α_{Roof}		0.89
Average Tank Paint Solar Absorbance	= $(\alpha_{Shell} + \alpha_{Roof}) / 2$ {Note A, Table 7.1-6}	α_{Tot}		0.89
Ideal Gas Constant,		R	psia ft³ / lbmole °R	10.731
Ambient Pressure		P_A	psia	14.490
Used Hs/D Type	Depending on Hs/D type, different equations are used for ter			Default
Hs/D		Hs/D		--

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Underground Tank?		UT		Aboveground
Heated Tank?		HT		No
Liquid Bulk Temperature	Heated Tanks Only	T_B	Degrees F	--
Insulated Tank?		IT		Partial
Pressure Tank?		PT		Atmospheric
Normal Operating Pressure	Only for Pressure Tanks	P_I	psig	0.0
Vapor Tight Roof		VTR		No
Control Device	*= None {No vapor tight roof}* *= User Specified*	CD		None
Control Device Efficiency		CD_{Eff}	%	--
Minimum Liquid Height	Update it to equal to the effective tank height	H_{Ln}	ft	1
Maximum Liquid Height	Update it to equal to the effective tank height	H_{LX}	ft	39
Dome Tank Roof Height	= $R_R - (R_R^2 - (D / 2)^2)^{0.5}$ {dome roof with D = 2 * R_S, Eqn. 1-20}	H_R	ft	--
Roof Outage	= S_R * (D / 2) / 3 {cone roof, Eqn. 1-17 and 1-18}	H_{RO}	ft	0.9
Breather Vent Pressure Setting	= 0 {No vapor tight roof, Eqn. 1-5 Note 3}	P_{BP}	psig	0.00
Breather Vent Vacuum Setting	= User Specified	P_{BV}	psig	0.00
Breather Vent Pressure Setting Range	*= 0 {No vapor tight roof}* *= P_{BP} - P_{BV} {Eqn. 1-10}*	ΔP_B	psig	0.00
Dome Roof Radius	Dome Roofs Only = user input between 0.8 to 1.2 * D {AP-42 7.1-15}	R_R	ft	--
Cone Roof Slope	Cone Roofs Only Default = 0.0625 ft/ft	S_R	ft/ft	0.0625
Tank Working Volume	= π/4 * D_E^2 * (H_{LX} - H_{LN}) {Eqn. 1-37}	V_{LX}	ft³	200,679
Days per Year	For leap years, days = 366	t_{yr}	days/yr	365

Emission Summary

Annual Throughput, gal	8,775,000	**Annual Emissions**	0.47
Annual Turnovers	5.84		
Month	**Emissions, lbs**	**Emissions, tons**	
Jan	31.17	0.016	
Feb	37.42	0.019	
Mar	58.43	0.029	
Apr	82.11	0.041	
May	111.07	0.056	
Jun	125.17	0.063	
Jul	138.14	0.069	
Aug	123.54	0.062	
Sep	95.92	0.048	
Oct	66.78	0.033	
Nov	43.83	0.022	
Dec	30.89	0.015	

Note: The emission summary table is pulled into the Tank Emissions tab using cell references A31:B42. The emission summary must remain at this cell reference to function properly.

Calculations

Parameter Title	Notes	Parameter Symbol	Units	Reference or Equation
Service				
Type of Substance	Select Organic Liquid, Petroleum Distillate, or Crude			
Contents of Tank	Select from list (add new compounds in 'VOLs' tab):			= User specified
Speciation Profile	Select from list (add new in 'Speciation Input' tab):			= User specified
Speciation Profile Type				= User specified
Monthly Throughput		Q	gal/month	= User specified
Days-In-Service	Total days per month minus the days tank has a service change, is out of service, or for non-routine events.	t_{IS}	days	
Constant in the vapor pressure equation	Used in ΔP_V only for petroleum liquids. If full speciation profile specified, leave blank.	B	°R	= Not Applicable {Organic liquids and full speciation profiles}
Average Liquid Height	Leave blank if unknown. Not applicable for horizontal Tanks. Fill out for tanks operating on level control.	H_L	ft	= User specified if known = H_{LX} / 2 {default}
Liquid Bulk Temperature	Input data through either Tank List tab, or Tank Throughput tab.	$T_{B\text{-input}}$	°F	= specified by user
Vapor Space Outage		H_{VO}	ft	= H_S - H_L + H_{RO} {all other fixed roof tanks, Eqn. 1-16} = (H_E / 2) {horizontal tanks only}
Daily Total Solar Insolation Factor		I	Btu / ft^2 day	
Vent Setting Correction Factor		K_B		When (P_{BP} > 0.03 psig) and (K_N * (P_{BP} + P_A) / (P_I + P_A)) > 1.0 {Eqn. 1-40} = (((P_I + P_A) / K_N) - $P_{VA,Tla}$) / (P_{BP} + P_A - $P_{VA,Tla}$) {Eqn. 1-41} Otherwise = 1
Vapor Space Expansion Factor	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in the tool that tank location is known. True vapor pressure based on liquid stock. If KE < 0, no standing losses occur. Per AP 42, 1> K_E ≥ 0.	K_E		= (ΔT_V / (T_{LA} + 459.67 °R)) + ((ΔP_V - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}
Working Loss Turnover (Saturation) Factor	Per Eqn. 1-35, annual threshold for turnovers is 36. Equation modified to a monthly form by converting the monthly turnovers to a theoretical annual turnover equivalent.	K_N		= (180 + (N * t_{yr} / t_{IS})) / (6 * (N * t_{yr} / t_{IS})) {(N * t_{yr} / t_{IS}) > 36, Eqn. 1-35} = 1 {(N * t_{yr} / t_{IS}) ≤ 36, Eqn. 1-35}
Working Loss Product Factor		K_P		= 0.75 {crude oils, Eqn. 1-35} = 1 {all other organic liquids}
Vented Vapor Saturation Factor	Constant 0.053 has units of 1/(psia-ft). True vapor pressure based on liquid surface temperature.	K_S		= 1 / (1 + 0.053 * $P_{VA,Tla}$ * H_{VO}) {Eqn. 1-21}
Vapor Molecular Weight	When using full speciation profiles, calculated as the weighted average of the M_V of each component.	M_V	lb/lb-mole	= VOL data of tank contents {partial speciation} M_V = Σ (M_{Vi} * ($P_{VA,Tla\text{-}i}$/$P_{VA,Tla}$)) {full speciation, Eqn. 1-23}
Liquid Molecular Weight		M_L	lb/lb-mole	M_L = 1 / Σ (Z_{Li} / M_{Li}) {full speciation}
Number of Turnovers per Month	Constant 5.614 has units of ft^3/bbl.	N		= 5.614 * Q * (bbl / 42 gal) / V_{LX} (Eqn. 1-36} and {Eqn. 1-37}
Average Daily Minimum Ambient Temperature		T_{AN}	°F	
Average Daily Maximum Ambient Temperature		T_{AX}	°F	
Daily Average Ambient Temperature		T_{AA}	°F	= (T_{AX} + T_{AN}) / 2 {Eqn. 1-30}
Daily Minimum Liquid Surf. Temperature, F		T_{LN}	°F	= T_{LA} - 0.25 * ΔT_V {Fig. 7.1-17}
Daily Maximum Liquid Surf. Temperature, F		T_{LX}	°F	= T_{LA} + 0.25 * ΔT_V {Fig. 7.1-17}
Daily Vapor Temperature Range	Constant 0.028 has units of (°R-ft^2-day/Btu)	ΔT_V	°R	For fully insulated tanks = 0 For uninsulated tanks: If default Hs/D = 0.7 * (TAX - TAN) + 0.02 * αTot * I {Eqn. 1-7} If specific Hs/D = [1 – 0.8 / (2.2 Hs/D + 1.9)] (TAX – TAN) + [0.042 αRI + 0.026 (Hs/D) αSI] / (2.2 Hs/D + 1.9) {Eqn. 1-6} For partial insulated tanks: = 0.6 * (TAX - TAN) + 0.02 * αR * I {Eqn. 1-8}

Parameter Title	1	2	3	4	5	6	7	8	9	10	11	12
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Type of Substance	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate
Contents of Tank	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2
Speciation Profile	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)
Speciation Profile Type	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation
Monthly Throughput	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250
Days-In-Service	31	28	31	30	31	30	31	31	30	31	30	31
Constant in the vapor pressure equation	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907
Average Liquid Height	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Outage	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Daily Total Solar Insolation Factor	823	1,079	1,409	1,773	1,936	1,936	1,936	1,718	1,491	1,211	949	753
Vent Setting Correction Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Vapor Space Expansion Factor	0.0516	0.0617	0.0735	0.0851	0.0870	0.0838	0.0831	0.0758	0.0696	0.0637	0.0572	0.0490
Working Loss Turnover (Saturation) Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Vented Vapor Saturation Factor	0.995	0.994	0.992	0.989	0.986	0.983	0.982	0.982	0.985	0.990	0.993	0.995
Vapor Molecular Weight	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Liquid Molecular Weight	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Number of Turnovers per Month	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Average Daily Minimum Ambient Temperature	38.00	40.40	46.60	53.50	62.90	70.10	73.20	72.70	67.30	56.20	45.90	39.10
Average Daily Maximum Ambient Temperature	57.40	61.20	68.70	76.00	83.40	88.50	91.30	90.40	85.50	76.40	67.20	58.40
Daily Average Ambient Temperature	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Minimum Liquid Surf. Temperature, F	44.79	47.68	54.34	61.38	70.08	76.54	79.54	78.90	73.67	63.27	53.36	45.86
Daily Maximum Liquid Surf. Temperature, F	57.93	63.52	73.51	83.90	93.46	99.29	102.20	99.50	92.40	80.11	68.19	58.35
Daily Vapor Temperature Range	26.29	31.69	38.34	45.06	46.76	45.50	45.32	41.20	37.46	33.68	29.67	24.98

Calculations																
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service					**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Daily Average Liquid Surf. Temperature	Constant 0.0079 has units of (°R-ft^2-day/btu).	T_{LA}	°F	For fully insulated tanks $= T_B$ For partial insulated tanks $= 0.3 * T_{AA} + 0.7 * T_B + 0.005 * \alpha_R * I$ {Eqn. 1-29} For uninsulated tanks $= 0.4 * T_{AA} + 0.6 * T_B + 0.005 * \alpha_{Tot} * I$ {Eqn. 1-28} for default Hs/D $= (0.5 - 0.8/(4.4Hs/D + 3.8))\ T_{AA} + (0.5 + 0.8/(4.4Hs/D+3.8)) * T_B + (0.021\alpha_R I + 0.013(Hs/D)\alpha_S I)/(4.4Hs/D+3.8)$ {Eqn. 1-27} for specific Hs/D	51.36	55.60	63.92	72.64	81.77	87.92	90.87	89.20	83.03	71.69	60.77	52.10
Liquid Bulk Temperature	If T_B is unknown, see AP-42 7.1 Eqn 1-27 Note 5.	T_B	°F	= specified by user {Insulated tanks only} $= T_{AA} + 0.003 * \alpha_{Tot} * I$ {Eqn. 1-31}	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Average Vapor Space Temperature	It is a new parameter in the new version of AP 42	T_V	°F	For fully insulated tanks = TB For partial insulated tanks = 0.6 * TAA + 0.4 * TB + 0.01 * αR * I {Eqn. 1-34} For uninsulated tanks If default Hs/D = 0.7 TAA + 0.3 TB + 0.009 α I {Eqn. 1-33} If specific Hs/D = [(2.2 Hs/D + 1.1) TAA + 0.8 TB + 0.021 αRI + 0.013 (Hs/D) αSI] / [2.2 Hs/D + 1.9] {Eqn. 1-32}	55.02	60.40	70.19	80.53	90.38	96.53	99.48	96.84	89.67	77.08	65.00	55.45
Vapor Pressure at Daily Av. Liquid Surf. Temp.	Used for speciated emissions and most vapor pressures. $P_{VA,Tla}$ uses T_{LA}.	$P_{VA,Tla}$	psia	*{full speciation profiles, Eqn. 1-24}:* Sum of partial true vapor pressures components. *{partial/no speciation profiles}: Calculated* vapor pressures at T (°F) with provided coefficients or interpolated with provided vapor pressures at different temperatures.	0.0049	0.0056	0.0074	0.0097	0.0129	0.0155	0.0169	0.0161	0.0134	0.0095	0.0066	0.0050
Vapor Pressure at Daily Min. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VN} uses T_{LN}.	P_{VN}	psia		0.0039	0.0043	0.0054	0.0068	0.0090	0.0110	0.0121	0.0118	0.0101	0.0072	0.0052	0.0040
Vapor Pressure at Daily Max. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VX} uses T_{LX}.	P_{VX}	psia		0.0061	0.0073	0.0100	0.0138	0.0183	0.0216	0.0235	0.0218	0.0177	0.0123	0.0085	0.0061
Daily Vapor Pressure Range		ΔP_V	psia	$= P_{VX} - P_{VN}$ {Eqn. 1-9}	0.002	0.003	0.005	0.007	0.009	0.011	0.011	0.010	0.008	0.005	0.003	0.002
Vapor Density		W_V	lb/ft^3	$= (M_V * P_{VA,Tla}) / (R * (T_{LA} + 459.67\ °R))$ {Eqn. 1-21}	0.0001142	0.0001304	0.0001685	0.0002184	0.0002843	0.0003383	0.0003671	0.0003511	0.0002959	0.0002133	0.0001535	0.0001170
Vapor Space Volume		V_V	ft^3	$= (\pi/4 * D_E^2) * H_{VO}$ {Eqn. 1-3}	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131
Heating Cycle																
Heating Cycle Period (days)	How many days in one heating cy	$Days_H$	days		--	--	--	--	--	--	--	--	--	--	--	--
Max Liquid Bulk Temperature	Highest liquid temperature in one heating cycle.	T_{BX}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Min Liquid Bulk Temperature	Lowest liquid temperature in one heating cycle.	T_{BN}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Average Liquid Bulk Temperature	Average liquid temperature in one heating cycle.	T_{BA}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Vapor Temperature Range		ΔT_{V-H}	°R	$= T_{BX} - T_{BN}$ {Eqn. 8-1}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Pressure Range		ΔP_{V-H}	psi	$=P_{VX} - P_{VN} = P_{BX} - P_{BN}$ {Eqn. 1-9}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Expansion Factor from Heating Cycle	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in	K_{E-H}		$= (\Delta T_{V-H} / (T_{LA} + 459.67\ °R)) + ((\Delta P_{V-H} - \Delta P_B) / (P_A - P_{VA,Tla})) \geq 0$ { Eqn. 1-5}	--	--	--	--	--	--	--	--	--	--	--	--
Standing Storage Loss	Uncontrolled emissions. No standing or breathing losses occur for underground tanks per AP-42 Eqn. 7.1-15.	L_S	lbs/month	= 0 {underground tanks only} $= t_{IS} * V_V * W_V * K_E * K_S$ {Eqn. 1-2}	20.0080	24.6656	41.9653	60.7694	83.2746	92.1042	102.2531	89.2206	67.0003	45.9270	28.8223	19.4527
Standing Storage Loss from Heating Cycles	Uncontrolled emissions. Standing losses occur when there is heating cycle for fully insulated tanks, Per AP-42 Section 7.1.3.8.4	L_{S-H}	lbs/month	= 0 {no heating cycle} $= t_{IS-H} * V_V * W_V * K_{E-H} * K_S$ {Eqn. 1-2}	--	--	--	--	--	--	--	--	--	--	--	--
Working Loss	Uncontrolled emissions. True vapor pressure based on liquid surface.	L_W	lbs/month	$= Q * (5.614\ ft^3/bbl) * (bbl / 42\ gal) * W_V * K_N * K_P * K_B$ {Eqn. 1-35}	11.16	12.75	16.47	21.35	27.79	33.06	35.88	34.32	28.92	20.85	15.01	11.44
Total Losses	**Uncontrolled emissions.**	L_T	**lbs/month**	**$= (L_S + L_W)$ {Eqn. 1-1}**	**31.17**	**37.42**	**58.43**	**82.11**	**111.07**	**125.17**	**138.14**	**123.54**	**95.92**	**66.78**	**43.83**	**30.89**

Fixed-Roof Tank Emissions - Monthly

Based on AP-42 (Nov 2019), Section 7.1.3.1.

Tool Last Updated: Mar 2021

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Reporting Year	2023

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Tank ID	Enter only Tank ID in this tab.			New Fuel Oil Tank No. 3
Tank Name	Text Description of Tank Name	TK_{name}		
Actual Location		Loc_{Act}		Box Springs, GA
Location for Calculation Purposes		Loc_{Calc}		Columbus, GA
Tank/Roof Type		TK_{roof}		VFR - Cone
Normal Capacity		Cap	gal	1,580,000
Diameter		D	ft	82
Shell Height or Length		H_S	ft	40
Effective Diameter	$= ((H_S * D) / (\pi/4))^{0.5}$ {horiz. tanks only, Eqn. 1-14} = D {all other fixed roof tanks}	D_E	ft	82.0
Effective Height	= π/4 * D {horiz. tanks only, Eqn. 1-15} = H_S -1 {all other fixed roof tanks}	H_E	ft	39.0
External Shell Color		SC_{ext}		Green/Dark
External Shell Paint Condition		PC_{Shell}		New
Roof Color/Shade		RC		Green/Dark
Roof Paint Condition		PC_{Roof}		New
Tank Shell Solar Absorbance		α_{Shell}		0.89
Tank Roof Paint Solar Absorbance		α_{Roof}		0.89
Average Tank Paint Solar Absorbance	$= (\alpha_{Shell} + \alpha_{Roof}) / 2$ {Note A, Table 7.1-6}	α_{Tot}		0.89
Ideal Gas Constant,		R	psia ft^3 / lbmole °R	10.731
Ambient Pressure		P_A	psia	14.490
Used Hs/D Type	Depending on Hs/D type, different equations are used for te			Default
Hs/D		Hs/D		--

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Underground Tank?		UT		Aboveground
Heated Tank?		HT		No
Liquid Bulk Temperature	Heated Tanks Only	T_B	Degrees F	--
Insulated Tank?		IT		Partial
Pressure Tank?		PT		Atmospheric
Normal Operating Pressure	Only for Pressure Tanks	P_I	psig	0.0
Vapor Tight Roof		VTR		No
Control Device	*= None {No vapor tight roof}* *= User Specified*	CD		None
Control Device Efficiency		CD_{Eff}	%	--
Minimum Liquid Height	Update it to equal to the effective tank height	H_{Ln}	ft	1
Maximum Liquid Height	Update it to equal to the effective tank height	H_{LX}	ft	39
Dome Tank Roof Height	$= R_R - (R_R^2 - (D / 2)^2)^{0.5}$ {dome roof with D = 2 * R_S, Eqn. 1-20}	H_R	ft	--
Roof Outage	$= S_R * (D / 2) / 3$ {cone roof, Eqn. 1-17 and 1-18}	H_{RO}	ft	0.9
Breather Vent Pressure Setting	= 0 {No vapor tight roof, Eqn. 1-5 Note 3} = User Specified	P_{BP}	psig	0.00
Breather Vent Vacuum Setting		P_{BV}	psig	0.00
Breather Vent Pressure Setting Range	*= 0 {No vapor tight roof}* $= P_{BP} - P_{BV}$ *{Eqn. 1-10}*	ΔP_B	psig	0.00
Dome Roof Radius	Dome Roofs Only = user input between 0.8 to 1.2 * D {AP-42 7.1-15}	R_R	ft	--
Cone Roof Slope	Cone Roofs Only Default = 0.0625 ft/ft	S_R	ft/ft	0.0625
Tank Working Volume	$= \pi/4 * D_E^2 * (H_{LX} - H_{LN})$ {Eqn. 1-37}	V_{LX}	ft^3	200,679
Days per Year	For leap years, days = 366	t_{yr}	days/yr	365

Emission Summary

Annual Throughput, gal	8,775,000	Annual Emissions	0.47
Annual Turnovers	5.84		
Month	**Emissions, lbs**	**Emissions, tons**	
Jan	31.17	0.016	
Feb	37.42	0.019	
Mar	58.43	0.029	
Apr	82.11	0.041	
May	111.07	0.056	
Jun	125.17	0.063	
Jul	138.14	0.069	
Aug	123.54	0.062	
Sep	95.92	0.048	
Oct	66.78	0.033	
Nov	43.83	0.022	
Dec	30.89	0.015	

Note: The emission summary table is pulled into the Tank Emissions tab using cell references A31:B42. The emission summary must remain at this cell reference to function properly.

Calculations

Parameter Title	Notes	Parameter Symbol	Units	Reference or Equation
Service				
Type of Substance	Select Organic Liquid, Petroleum Distillate, or Crude			
Contents of Tank	Select from list (add new compounds in 'VOLs' tab):			= User specified
Speciation Profile	Select from list (add new in 'Speciation Input' tab):			= User specified
Speciation Profile Type				= User specified
Monthly Throughput		Q	gal/month	= User specified
Days-In-Service	Total days per month minus the days tank has a service change, is out of service, or for non-routine events.	t_{IS}	days	
Constant in the vapor pressure equation	Used in ΔP_V only for petroleum liquids. If full speciation profile specified, leave blank.	B	°R	= Not Applicable {Organic liquids and full speciation profiles}
Average Liquid Height	Leave blank if unknown. Not applicable for horizontal Tanks. Fill out for tanks operating on level control.	H_L	ft	= User specified if known = H_{LX} / 2 {default}
Liquid Bulk Temperature	Input data through either Tank List tab, or Tank Throughput tab.	$T_{B\text{-input}}$	°F	= specified by user
Vapor Space Outage		H_{VO}	ft	= H_S - H_L + H_{RO} {all other fixed roof tanks, Eqn. 1-16} = (H_E / 2) {horizontal tanks only}
Daily Total Solar Insolation Factor		I	Btu / ft^2 day	
Vent Setting Correction Factor		K_B		When (P_{BP} > 0.03 psig) and (K_N * (P_{BP} + P_A) / (P_I + P_A)) > 1.0 {Eqn. 1-40} = (((P_I + P_A) / K_N) - $P_{VA,Tla}$) / (P_{BP} + P_A - $P_{VA,Tla}$) {Eqn. 1-41} Otherwise = 1
Vapor Space Expansion Factor	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in the tool that tank location is known. True vapor pressure based on liquid stock. If KE < 0, no standing losses occur. Per AP 42, 1> K_E ≥ 0.	K_E		= (ΔT_V / (T_{LA} + 459.67 °R)) + ((ΔP_V - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}
Working Loss Turnover (Saturation) Factor	Per Eqn. 1-35, annual threshold for turnovers is 36. Equation modified to a monthly form by converting the monthly turnovers to a theoretical annual turnover equivalent.	K_N		= (180 + (N * t_{yr} / t_{IS})) / (6 * (N * t_{yr} / t_{IS})) {(N * t_{yr} / t_{IS}) > 36, Eqn. 1-35} = 1 {(N * t_{yr} / t_{IS}) ≤ 36, Eqn. 1-35}
Working Loss Product Factor		K_P		= 0.75 {crude oils, Eqn. 1-35} = 1 {all other organic liquids}
Vented Vapor Saturation Factor	Constant 0.053 has units of 1/(psia-ft). True vapor pressure based on liquid surface temperature.	K_S		= 1 / (1 + 0.053 * $P_{VA,Tla}$ * H_{VO}) {Eqn. 1-21}
Vapor Molecular Weight	When using full speciation profiles, calculated as the weighted average of the M_V of each component.	M_V	lb/lb-mole	= VOL data of tank contents {partial speciation} M_V = Σ (M_{Vi} * ($P_{VA,Tla\text{-}i}$/$P_{VA,Tla}$)) {full speciation, Eqn. 1-23}
Liquid Molecular Weight		M_L	lb/lb-mole	M_L = 1 / Σ (Z_{Li} / M_{Li}) {full speciation}
Number of Turnovers per Month	Constant 5.614 has units of ft^3/bbl.	N		= 5.614 * Q * (bbl / 42 gal) / V_{LX} (Eqn. 1-36} and {Eqn. 1-37}
Average Daily Minimum Ambient Temperature		T_{AN}	°F	
Average Daily Maximum Ambient Temperature		T_{AX}	°F	
Daily Average Ambient Temperature		T_{AA}	°F	= (T_{AX} + T_{AN}) / 2 {Eqn. 1-30}
Daily Minimum Liquid Surf. Temperature, F		T_{LN}	°F	= T_{LA} - 0.25 * ΔT_V {Fig. 7.1-17}
Daily Maximum Liquid Surf. Temperature, F		T_{LX}	°F	= T_{LA} + 0.25 * ΔT_V {Fig. 7.1-17}
Daily Vapor Temperature Range	Constant 0.028 has units of (°R-ft^2-day/Btu)	ΔT_V	°R	For fully insulated tanks = 0 For uninsulated tanks: If default Hs/D = 0.7 * (TAX - TAN) + 0.02 * αTot * I {Eqn. 1-7} If specific Hs/D = [1 – 0.8 / (2.2 Hs/D + 1.9)] (TAX – TAN) + [0.042 αRI + 0.026 (Hs/D) αSI] / (2.2 Hs/D + 1.9) {Eqn. 1-6} For partial insulated tanks: = 0.6 * (TAX - TAN) + 0.02 * αR * I {Eqn. 1-8}

Parameter Title	1	2	3	4	5	6	7	8	9	10	11	12
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Service	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Type of Substance	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate
Contents of Tank	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2
Speciation Profile	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)
Speciation Profile Type	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation
Monthly Throughput	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250
Days-In-Service	31	28	31	30	31	30	31	31	30	31	30	31
Constant in the vapor pressure equation	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907
Average Liquid Height	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Outage	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Daily Total Solar Insolation Factor	823	1,079	1,409	1,773	1,936	1,936	1,936	1,718	1,491	1,211	949	753
Vent Setting Correction Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Vapor Space Expansion Factor	0.0516	0.0617	0.0735	0.0851	0.0870	0.0838	0.0831	0.0758	0.0696	0.0637	0.0572	0.0490
Working Loss Turnover (Saturation) Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Vented Vapor Saturation Factor	0.995	0.994	0.992	0.989	0.986	0.983	0.982	0.982	0.985	0.990	0.993	0.995
Vapor Molecular Weight	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Liquid Molecular Weight	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Number of Turnovers per Month	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Average Daily Minimum Ambient Temperature	38.00	40.40	46.60	53.50	62.90	70.10	73.20	72.70	67.30	56.20	45.90	39.10
Average Daily Maximum Ambient Temperature	57.40	61.20	68.70	76.00	83.40	88.50	91.30	90.40	85.50	76.40	67.20	58.40
Daily Average Ambient Temperature	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Minimum Liquid Surf. Temperature, F	44.79	47.68	54.34	61.38	70.08	76.54	79.54	78.90	73.67	63.27	53.36	45.86
Daily Maximum Liquid Surf. Temperature, F	57.93	63.52	73.51	83.90	93.46	99.29	102.20	99.50	92.40	80.11	68.19	58.35
Daily Vapor Temperature Range	26.29	31.69	38.34	45.06	46.76	45.50	45.32	41.20	37.46	33.68	29.67	24.98

Calculations																
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service					**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Daily Average Liquid Surf. Temperature	Constant 0.0079 has units of (°R-ft^2-day/btu).	T_{LA}	°F	For fully insulated tanks $= T_B$ For partial insulated tanks $= 0.3 * T_{AA} + 0.7 * T_B + 0.005 * \alpha_R * I$ {Eqn. 1-29} For uninsulated tanks $= 0.4 * T_{AA} + 0.6 * T_B + 0.005 * \alpha_{Tot} * I$ {Eqn. 1-28} for default Hs/D $= (0.5 - 0.8/(4.4Hs/D + 3.8))\ T_{AA} + (0.5 + 0.8/(4.4Hs/D+3.8)) * T_B + (0.021\alpha_R I + 0.013(Hs/D)\alpha_S I)/(4.4Hs/D+3.8)$ {Eqn. 1-27} for specific Hs/D	51.36	55.60	63.92	72.64	81.77	87.92	90.87	89.20	83.03	71.69	60.77	52.10
Liquid Bulk Temperature	If T_B is unknown, see AP-42 7.1 Eqn 1-27 Note 5.	T_B	°F	= specified by user {Insulated tanks only} $= T_{AA} + 0.003 * \alpha_{Tot} * I$ {Eqn. 1-31}	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Average Vapor Space Temperature	It is a new parameter in the new version of AP 42	T_V	°F	For fully insulated tanks = TB For partial insulated tanks = 0.6 * TAA + 0.4 * TB + 0.01 * αR * I {Eqn. 1-34} For uninsulated tanks If default Hs/D = 0.7 TAA + 0.3 TB + 0.009 α I {Eqn. 1-33} If specific Hs/D = [(2.2 Hs/D + 1.1) TAA + 0.8 TB + 0.021 αRI + 0.013 (Hs/D) αSI] / [2.2 Hs/D + 1.9] {Eqn. 1-32}	55.02	60.40	70.19	80.53	90.38	96.53	99.48	96.84	89.67	77.08	65.00	55.45
Vapor Pressure at Daily Av. Liquid Surf. Temp.	Used for speciated emissions and most vapor pressures. $P_{VA,Tla}$ uses T_{LA}.	$P_{VA,Tla}$	psia	*{full speciation profiles, Eqn. 1-24}:* Sum of partial true vapor pressures components. *{partial/no speciation profiles}: Calculated* vapor pressures at T (°F) with provided coefficients or interpolated with provided vapor pressures at different temperatures.	0.0049	0.0056	0.0074	0.0097	0.0129	0.0155	0.0169	0.0161	0.0134	0.0095	0.0066	0.0050
Vapor Pressure at Daily Min. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VN} uses T_{LN}.	P_{VN}	psia		0.0039	0.0043	0.0054	0.0068	0.0090	0.0110	0.0121	0.0118	0.0101	0.0072	0.0052	0.0040
Vapor Pressure at Daily Max. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VX} uses T_{LX}.	P_{VX}	psia		0.0061	0.0073	0.0100	0.0138	0.0183	0.0216	0.0235	0.0218	0.0177	0.0123	0.0085	0.0061
Daily Vapor Pressure Range		ΔP_V	psia	$= P_{VX} - P_{VN}$ {Eqn. 1-9}	0.002	0.003	0.005	0.007	0.009	0.011	0.011	0.010	0.008	0.005	0.003	0.002
Vapor Density		W_V	lb/ft^3	$= (M_V * P_{VA,Tla}) / (R * (T_{LA} + 459.67\ °R))$ {Eqn. 1-21}	0.0001142	0.0001304	0.0001685	0.0002184	0.0002843	0.0003383	0.0003671	0.0003511	0.0002959	0.0002133	0.0001535	0.0001170
Vapor Space Volume		V_V	ft^3	$= (\pi/4 * D_E^2) * H_{VO}$ {Eqn. 1-3}	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131
Heating Cycle																
Heating Cycle Period (days)	How many days in one heating cy	$Days_H$	days		--	--	--	--	--	--	--	--	--	--	--	--
Max Liquid Bulk Temperature	Highest liquid temperature in one heating cycle.	T_{BX}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Min Liquid Bulk Temperature	Lowest liquid temperature in one heating cycle.	T_{BN}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Average Liquid Bulk Temperature	Average liquid temperature in one heating cycle.	T_{BA}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Vapor Temperature Range		ΔT_{V-H}	°R	$= T_{BX} - T_{BN}$ {Eqn. 8-1}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Pressure Range		ΔP_{V-H}	psi	$= P_{VX} - P_{VN} = P_{BX} - P_{BN}$ {Eqn. 1-9}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Expansion Factor from Heating Cycle	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in	K_{E-H}		$= (\Delta T_{V-H} / (T_{LA} + 459.67\ °R)) + ((\Delta P_{V-H} - \Delta P_B) / (P_A - P_{VA,Tla})) \geq 0$ { Eqn. 1-5}	--	--	--	--	--	--	--	--	--	--	--	--
Standing Storage Loss	Uncontrolled emissions. No standing or breathing losses occur for underground tanks per AP-42 Eqn. 7.1-15.	L_S	lbs/month	= 0 {underground tanks only} $= t_{IS} * V_V * W_V * K_E * K_S$ {Eqn. 1-2}	20.0080	24.6656	41.9653	60.7694	83.2746	92.1042	102.2531	89.2206	67.0003	45.9270	28.8223	19.4527
Standing Storage Loss from Heating Cycles	Uncontrolled emissions. Standing losses occur when there is heating cycle for fully insulated tanks, Per AP-42 Section 7.1.3.8.4	L_{S-H}	lbs/month	= 0 {no heating cycle} $= t_{IS-H} * V_V * W_V * K_{E-H} * K_S$ {Eqn. 1-2}	--	--	--	--	--	--	--	--	--	--	--	--
Working Loss	Uncontrolled emissions. True vapor pressure based on liquid surface.	L_W	lbs/month	$= Q * (5.614\ ft^3/bbl) * (bbl / 42\ gal) * W_V * K_N * K_P * K_B$ {Eqn. 1-35}	11.16	12.75	16.47	21.35	27.79	33.06	35.88	34.32	28.92	20.85	15.01	11.44
Total Losses	**Uncontrolled emissions.**	$\mathbf{L_T}$	**lbs/month**	**$= (L_S + L_W)$ {Eqn. 1-1}**	**31.17**	**37.42**	**58.43**	**82.11**	**111.07**	**125.17**	**138.14**	**123.54**	**95.92**	**66.78**	**43.83**	**30.89**

Table B-31. 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	9.96	42.68	0.01	32.73	--	32.73	25	Yes
Total PM_{10}	34.33	142.13	0.02	107.81	--	107.81	15	Yes
Total $PM_{2.5}$	34.33	142.13	0.02	107.81	--	107.81	10	Yes
SO_2	1.50	7.17	0.23	5.90	--	5.90	40	No
NO_X	73.90	627.29	0.77	554.16	--	554.16	40	Yes
VOC	6.37	50.36	0.97	44.97	--	44.97	40	Yes
CO	74.60	388.32	0.46	314.18	--	314.18	100	Yes
CO_2e	298,178	1,253,010	132.28	954,964	--	954,964	75,000	Yes
Lead	--	1.7E-02	--	1.7E-02	--	1.7E-02	0.60	No
Sulfuric Acid Mist	0.15	0.72	0.02	0.59	--	0.59	7.00	No

1. The four existing site turbines are the modified units with respect to this PSD assessment.
2. The two fuel oil storage tanks and diesel fire pump are new units with respect to this PSD assessment.
3. Emissions Increase from New and Modified Units (tpy) = New Unit Potential Emissions (tpy) + Modified Unit Potential 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. PTE CALCULATIONS

Table C-1. Potential Emission Factors for Turbine Combustion of Natural Gas
Combustion Turbine Nos. 1 - 4

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis
SO_2	6.00E-04	See Note 1
NO_X	4.49E-02	See Note 2
CO	1.82E-02	See Note 2
Total PM	1.37E-02	See Note 2
Filterable PM	3.97E-03	See Note 3
Condensable PM	9.73E-03	See Note 3
Total PM_{10}	1.37E-02	See Note 2
Total $PM_{2.5}$	1.37E-02	See Note 2
VOC	2.54E-03	See Note 2
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	See Note 1
GHGs		
CO_2	118.86	See Note 4
CH_4	2.20E-03	See Note 5
N_2O	2.20E-04	See Note 5
CO_2e	118.98	See Note 6

1. SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens.

3. Emission factors for filterable and condensable PM from natural gas combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = $F_c * U_f * MW_{CO2}$
CO_2 emission factor (lb/MMBtu) = 1,040 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

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 C-2. Potential Emission Factors for Turbine Combustion of Fuel Oil Combustion Turbine Nos. 1 - 4

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis
SO_2	1.51E-03	See Note 1
NO_X	1.68E-01	See Note 2
CO	3.64E-02	See Note 2
Total PM	1.70E-02	See Note 2
Filterable PM	6.12E-03	See Note 3
Condensable PM	1.09E-02	See Note 3
Total PM_{10}	1.70E-02	See Note 2
Total $PM_{2.5}$	1.70E-02	See Note 2
VOC	6.96E-03	See Note 2
Lead	1.40E-05	See Note 3
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	See Note 1
GHGs		
CO_2	162.29	See Note 4
CH_4	6.61E-03	See Note 5
N_2O	1.32E-03	See Note 5
CO_2e	162.85	See Note 6

1. Emission factor for SO_2 derived from Equation D-2 in Appendix D to 40 CFR 75.
SO_2 emission factor (lb/MMBtu) = 2.0 * Density (lb/gal) / HHV (MMBtu/gal) * $\%S_{oil}$ / 100.0
SO_2 emission factor (lb/MMBtu) = 2.0 * 7.05 (lb/gal) / 0.140 (MMBtu/gal) * 0.0015 (%S) / 100.0
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens.
3. Emission factors for lead, as well as filterable and condensable PM from fuel oil combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = $F_c * U_f * MW_{CO2}$
CO_2 emission factor (lb/MMBtu) = 1,420 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

5. 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.
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 C-3. Potential Factors for Turbine Startup/Shutdown Operations
Combustion Turbine Nos. 1 - 4

Pollutant	Emission Factors[1] (lb/event)	Events[2]
Startup Natural Gas		
NO_X	74	227 events/yr
CO	276	
VOC	30.8	
Shutdown Natural Gas		
NO_X	76	227 events/yr
CO	82	
VOC	9.0	
Startup Fuel Oil		
NO_X	244	27 events/yr
CO	514	
VOC	57.7	
Startup/Shutdown Fuel Oil		
NO_X	286	27 events/yr
CO	314	
VOC	35.1	

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.

2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type.

Table C-4. Fuel Heater Potential Emission Factors

Pollutant	Emission Factor (lb/MMBtu, HHV basis)	Emission Factor Basis
SO_2	5.88E-04	See Note 1
NO_X	1.11E-01	See Note 2
CO	1.99E-02	See Note 3
Total PM	7.45E-03	See Note 1
Condensable PM	5.59E-03	See Note 1
Filterable PM	1.86E-03	See Notes 1, 5
Total PM_{10}	7.45E-03	See Notes 1, 5
Total $PM_{2.5}$	7.45E-03	See Notes 1, 5
VOC	5.39E-03	See Note 2
Lead	4.90E-07	See Note 1
H_2SO_4	5.88E-05	See Note 4
GHGs		
CO_2	116.98	See Note 6
CH_4	2.20E-03	See Note 6
N_2O	2.20E-04	See Note 6
CO_2e	117.10	See Note 7

1. Emission factors from AP-42, Section 1.4, Table 1.4-2. The emission factors were converted from lb/MMscf to lb/MMBtu using the average natural gas heating value of 1,020 MMBtu/MMscf.

2. Each fuel gas heater has a guaranteed maximum NO_x emission rate of 30 ppm at 15% O_2, which is equivalent to an emission rate of 0.1105 lb/MMBtu, HHV basis.

3. Each fuel gas heater has a guaranteed maximum CO emission rate of 0.022 lb/MMBtu, LHV basis. This emission rate was converted from LHV basis to HHV basis using a ratio of 1.108 HHV/LHV for natural gas.

4. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

5. All filterable PM is assumed to be less than 2.5 microns in diameter, per footnote c to AP-42, Section 1.4, Table 1.4-2.

6. 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.

7. 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 C-5. Turbine HAP/TAP Emission Factors for Natural Gas Combustion

Pollutant	Federal HAP (Yes/No)	TAP? (Yes/No)	Emission Factor (lb/MMBtu)	Source[1]
1,3-Butadiene	Yes	Yes	6.05E-08	U.S. EPA
Acetaldehyde	Yes	Yes	4.31E-05	U.S. EPA
Acrolein	Yes	Yes	5.60E-06	U.S. EPA
Benzene	Yes	Yes	1.14E-05	U.S. EPA
Ethylbenzene	Yes	Yes	2.28E-05	U.S. EPA
Formaldehyde	Yes	Yes	1.07E-04	CARB
Naphthalene	Yes	Yes	6.33E-07	U.S. EPA
PAH	Yes	No	4.71E-07	U.S. EPA
Propylene Oxide	Yes	Yes	2.86E-05	U.S. EPA
Toluene	Yes	Yes	6.80E-05	U.S. EPA
Xylene (Total)	Yes	Yes	6.51E-05	U.S. EPA

1. Emission factors taken from U.S. EPA Inventory Database for Stationary Combustion Turbines, published May 4, 2000, except for the formaldehyde factor for natural gas, which is from the California Air Resources Board (CARB). Emission factors represent test results from turbines models rated.

Table C-6. Turbine HAP/TAP Emission Factors for Fuel Oil Combustion

Pollutant	Federal HAP (Yes/No)	TAP? (Yes/No)	Emission Factor (lb/MMBtu)	Source
1,3-Butadiene	Yes	Yes	2.28E-04	U.S. EPA
Acrolein	Yes	Yes	2.36E-04	U.S. EPA
Benzene	Yes	Yes	1.21E-04	U.S. EPA
Formaldehyde	Yes	Yes	3.16E-04	U.S. EPA
Naphthalene	Yes	Yes	2.95E-05	U.S. EPA
PAH	Yes	No	3.39E-05	U.S. EPA
Toluene	Yes	Yes	2.33E-04	U.S. EPA
Xylene (Total)	Yes	Yes	2.28E-04	U.S. EPA
Arsenic	Yes	Yes	4.13E-06	U.S. EPA
Beryllium	Yes	Yes	3.28E-07	U.S. EPA
Cadmium	Yes	Yes	3.02E-06	U.S. EPA
Chromium	Yes	Yes	8.21E-06	U.S. EPA
Chromium (VI)	Yes	Yes	8.31E-08	U.S. EPA
Lead	Yes	Yes	See Potential Criteria Pollutant Emission Factors	
Manganese	Yes	Yes	4.31E-04	U.S. EPA
Mercury	Yes	Yes	6.10E-07	U.S. EPA
Nickel	Yes	Yes	1.77E-04	U.S. EPA
Selenium	Yes	Yes	1.26E-05	U.S. EPA

1. Emission factors taken from U.S. EPA Inventory Database for Stationary Combustion Turbines, published May 4, 2000, except for the formaldehyde factor for natural gas, which is from the California Air Resources Board (CARB). Emission factors represent test results from turbines models rated.

Table C-7. Heater HAP/TAP Emission Factors for Natural Gas Combustion

Pollutant	Federal HAP (Yes/No)	TAP? (Yes/No)	Emission Factor (lb/MMscf)	Source
2-Methylnaphthalene	Yes	No	2.40E-05	AP-42
3-Methylchloranthrene	Yes	No	1.80E-06	AP-42
7,12-Dimethylbenz(a)anthracene	Yes	No	1.60E-05	AP-42
Acenaphthene	Yes	No	1.80E-06	AP-42
Acenaphthylene	Yes	No	1.80E-06	AP-42
Anthracene	Yes	No	2.40E-06	AP-42
Benzene	Yes	Yes	2.10E-03	AP-42
Benz(a)anthracene	Yes	No	1.80E-06	AP-42
Benzo(a)pyrene	Yes	No	1.20E-06	AP-42
Benzo(b)fluoranthene	Yes	No	1.80E-06	AP-42
Benzo(g,h,i)perylene	Yes	No	1.20E-06	AP-42
Benzo(k)fluoranthene	Yes	No	1.80E-06	AP-42
Chrysene	Yes	No	1.80E-06	AP-42
Dibenz(a,h)anthracene	Yes	No	1.20E-06	AP-42
Dichlorobenzene	Yes	No	1.20E-03	AP-42
Fluoranthene	Yes	No	3.00E-06	AP-42
Fluorene	Yes	No	2.80E-06	AP-42
Formaldehyde	Yes	Yes	7.50E-02	AP-42
Hexane	Yes	Yes	1.80E+00	AP-42
Indeno(1,2,3-cd)pyrene	Yes	No	1.80E-06	AP-42
Naphthalene	Yes	Yes	6.10E-04	AP-42
Phenanthrene	Yes	No	1.70E-05	AP-42
Pyrene	Yes	No	5.00E-06	AP-42
Toluene	Yes	Yes	3.40E-03	AP-42
Arsenic	Yes	Yes	2.00E-04	AP-42
Beryllium	Yes	Yes	1.20E-05	AP-42
Cadmium	Yes	Yes	1.10E-03	AP-42
Chromium	Yes	Yes	1.40E-03	AP-42
Chromium (VI)	Yes	Yes	5.60E-05	Note 2
Cobalt	Yes	Yes	8.40E-05	AP-42
Lead	Yes	Yes	See Potential Criteria Pollutant Emission Factors	
Manganese	Yes	Yes	3.80E-04	AP-42
Mercury	Yes	Yes	2.60E-04	AP-42
Nickel	Yes	Yes	2.10E-03	AP-42
Selenium	Yes	Yes	2.40E-05	AP-42

1. Emission factors for natural gas combustion taken from AP-42 Section 1.4, Natural Gas Combustion, July 1998, Tables 1.4-3, -4.

2. Chromium (VI) assumed to be 4% of the AP-42 Section 1.4 emission factor for Chromium per discussions with EPD in July 2022.

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table C-8. Potential 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	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table C-1 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential 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	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table C-9. Potential 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	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table C-2 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)

Table C-10. Potential Emissions from Turbine No. 1 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Potential Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.
2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Potential Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.
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 C-11. Potential Criteria Pollutant Emissions from Combustion Turbine No. 1

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table C-12. Potential 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	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table C-1 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential 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	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table C-13. Potential 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	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table C-2 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)

Table C-14. Potential Emissions from Turbine No. 2 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Potential Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.
2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Potential Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.
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 C-15. Potential Criteria Pollutant Emissions from Combustion Turbine No. 2

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table C-16. Potential 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	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

1. See Table C-1 for details on emission factors for turbines combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential 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	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table C-17. Potential 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	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

1. See Table C-2 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)

Table C-18. Potential Emissions from Turbine No. 3 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Potential Emissions[3] (lb/hr)	(tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.
2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Potential Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.
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 C-19. Potential Criteria Pollutant Emissions from Combustion Turbine No. 3

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,180	MMBtu/hr, HHV	
Operating Hours	3,296	hrs/yr	NO_X, CO, VOC
	3,750	hrs/yr	Other Pollutants

Table C-20. Potential 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	0.71	1.33
NO_X	4.49E-02	52.93	87.24
CO	1.82E-02	21.50	35.43
Total PM	1.37E-02	16.17	30.31
Filterable PM	3.97E-03	4.69	8.79
Condensable PM	9.73E-03	11.48	21.52
Total PM_{10}	1.37E-02	16.17	30.31
Total $PM_{2.5}$	1.37E-02	16.17	30.31
VOC	2.54E-03	3.00	4.94
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	7.1E-02	1.3E-01
GHGs			
CO_2	118.86	140,251	262,971
CH_4	2.20E-03	2.60	4.88
N_2O	2.20E-04	0.26	0.49
CO_2e	118.98	140,394	263,239

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. Potential 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	1,365	MMBtu/hr, HHV	
Turbine Operating Hours	396	hrs/yr	NOx, CO, VOC
	450	hrs/yr	Other Pollutants

Table C-21. Potential 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	1.51E-03	2.06	0.46
NO_X	1.68E-01	229.32	45.41
CO	3.64E-02	49.69	9.84
Total PM	1.70E-02	23.21	5.22
Filterable PM	6.12E-03	8.35	1.88
Condensable PM	1.09E-02	14.85	3.34
Total PM_{10}	1.70E-02	23.21	5.22
Total $PM_{2.5}$	1.70E-02	23.21	5.22
VOC	6.96E-03	9.50	1.88
Lead	1.40E-05	1.9E-02	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	1.51E-04	2.1E-01	4.6E-02
GHGs			
CO_2	162.29	221,520	49,842
CH_4	6.61E-03	9.03	2.03
N_2O	1.32E-03	1.81	0.41
CO_2e	162.85	222,284	50,014

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)

Table C-22. Potential Emissions from Turbine No. 4 Startup/Shutdown Operations

Pollutant	Emission Factor[1] (lb/event)	Events[2]	Potential Emissions[3] (lb/hr)	Potential Emissions[3] (tpy)
Normal Operation Period[4]				
NO_X	--	--	229.32	132.64
CO	--	--	49.69	45.27
VOC	--	--	9.50	6.82
Startup Period Natural Gas				
NO_X	74	227	74.00	8.40
CO	276		276.00	31.33
VOC	30.8		30.80	3.50
Shutdown Period Natural Gas				
NO_X	76	227	76.00	8.63
CO	82		82.00	9.31
VOC	9		9.00	1.02
Startup Period Fuel Oil				
NO_X	244	27	244.00	3.29
CO	514		514.00	6.94
VOC	58		57.70	0.78
Shutdown Period Fuel Oil				
NO_X	286	27	286.00	3.86
CO	314		314.00	4.24
VOC	35		35.10	0.47
Annual Emissions[5]				
NO_X	--	--	--	156.82
CO	--	--	--	97.08
VOC	--	--	--	12.59

1. Startup/shutdown emission factors as provided from Siemens. These factors represent total emissions for an hour in which a startup or shutdown occurs.
2. Assumes potential startup/shutdown events for each turbine are evenly distributed based on potential operating time per fuel type. The estimated duration of each startup and shutdown event is 30 minutes.
3. Potential Emissions for Startup/Shutdown Period (tpy) = Emission Factor (lb/event) * Events / 2,000 (lbs/ton)
Potential Emissions for Startup/Shutdown Period (lb/hr) = Emission Factor (lb/event) * 2,000 (lbs/ton)
The Emission Factor (lb/event) is defined as an hour in which a startup or shutdown occurs.
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 C-23. Potential Criteria Pollutant Emissions from Combustion Turbine No. 4

Pollutant	Annual Emissions (tpy)
SO_2	1.79
NO_X	156.82
CO	97.08
Total PM	35.53
Filterable PM	10.67
Condensable PM	24.86
Total PM_{10}	35.53
Total $PM_{2.5}$	35.53
VOC	12.59
Lead	4.3E-03
Sulfuric Acid Mist (H_2SO_4)	0.18
GHGs	313,253

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,159	MMBtu/hr, HHV
Operating Hours	3,750	hrs/yr

Table C-24. Potential Criteria Pollutant Emissions from Turbine No. 5 Natural Gas Combustion

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis (lb/MMBtu)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
SO_2	6.00E-04	See Note 1	0.70	1.30
NO_X	4.49E-02	See Note 2	52.02	160.60
CO	1.90E-02	See Note 2	22.01	42.00
Total PM	2.30E-02	See Note 2	26.65	49.96
Filterable PM	6.67E-03	See Note 3	7.73	14.49
Condensable PM	1.63E-02	See Note 3	18.92	35.47
Total PM_{10}	2.30E-02	See Note 2	26.65	49.96
Total $PM_{2.5}$	2.30E-02	See Note 2	26.65	49.96
VOC	8.60E-03	See Note 2	9.96	18.68
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	See Note 1	7.0E-02	1.3E-01
GHGs[5,6,7]				
CO_2	118.86	See Note 4	137,701	258,189
CH_4	2.20E-03	See Note 5	2.55	4.79
N_2O	2.20E-04	See Note 5	0.26	0.48
CO_2e	118.98	See Note 6	137,841	258,451

1. SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens. Potential Annual Emissions for NO_X and CO based on overall Permit Limit in V-07-0 Condition 3.3.9.

3. Emission factors for filterable and condensable PM from natural gas combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = F_c * U_f * MW_{CO2}
CO_2 emission factor (lb/MMBtu) = 1,040 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

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

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,395	MMBtu/hr, HHV
Turbine Operating Hours	450	hrs/yr

Table C-25. Potential Criteria Pollutant Emissions from Turbine No. 5 Fuel Oil Combustion

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMBtu)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
SO_2	5.04E-02	Note 1	70.23	15.80
NO_X	1.68E-01	Note 2	234.28	160.60
CO	3.80E-02	Note 2	52.99	42.00
Total PM	2.30E-02	Note 1	32.07	7.22
Filterable PM	8.28E-03	Note 3	11.55	2.60
Condensable PM	1.47E-02	Note 3	20.53	4.62
Total PM_{10}	2.30E-02	Note 1	32.07	7.22
Total $PM_{2.5}$	2.30E-02	Note 1	32.07	7.22
VOC	1.49E-02	Note 1	20.78	4.68
Lead[4]	1.40E-05	Note 3	1.95E-02	4.39E-03
Sulfuric Acid Mist (H_2SO_4)	5.04E-03	Note 1	7.02	1.58
GHGs [5,6,7]				
CO_2	162.29	See Note 4	226,314	50,921
CH_4	6.61E-03	See Note 5	9.22	2.08
N_2O	1.32E-03	See Note 5	1.84	0.42
CO_2e	162.85	See Note 6	227,094	51,096

1. Emission factor for SO_2 derived from Equation D-2 in Appendix D to 40 CFR 75.
SO_2 emission factor (lb/MMBtu) = 2.0 * Density (lb/gal) / HHV (MMBtu/gal) * $\%S_{oil}$ / 100.0
SO_2 emission factor (lb/MMBtu) = 2.0 * 7.05 (lb/gal) / 0.140 (MMBtu/gal) * 0.05 (%S) / 100.0
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens. Potential Annual Emissions for NO_X and CO based on overall Permit Limit in V-07-0 Condition 3.3.9.

3. Emission factors for lead, as well as filterable and condensable PM from fuel oil combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = $F_c * U_f * MW_{CO2}$
CO_2 emission factor (lb/MMBtu) = 1,420 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

5. 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.

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 C-26. Potential Criteria Pollutant Emissions from Combustion Turbine No. 5

Pollutant	Annual Emissions (tpy)
SO_2	17.10
NO_X	160.60
CO	42.00
Total PM	57.18
Filterable PM	17.09
Condensable PM	40.09
Total PM_{10}	57.18
Total $PM_{2.5}$	57.18
VOC	23.36
Lead	4.4E-03
Sulfuric Acid Mist (H_2SO_4)	1.71
GHGs	309,548

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input	1,159	MMBtu/hr, HHV
Operating Hours	3,750	hrs/yr

Table C-27. Potential Criteria Pollutant Emissions from Turbine No. 6 Natural Gas Combustion

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Basis (lb/MMBtu)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
SO_2	6.00E-04	See Note 1	0.70	1.30
NO_X	4.49E-02	See Note 2	52.02	160.60
CO	1.90E-02	See Note 2	22.01	42.00
Total PM	2.30E-02	See Note 2	26.65	49.96
Filterable PM	6.67E-03	See Note 3	7.73	14.49
Condensable PM	1.63E-02	See Note 3	18.92	35.47
Total PM_{10}	2.30E-02	See Note 2	26.65	49.96
Total $PM_{2.5}$	2.30E-02	See Note 2	26.65	49.96
VOC	8.60E-03	See Note 2	9.96	18.68
Sulfuric Acid Mist (H_2SO_4)	6.00E-05	See Note 1	7.0E-02	1.3E-01
GHGs[5,6,7]				
CO_2	118.86	See Note 4	137,701	258,189
CH_4	2.20E-03	See Note 5	2.55	4.79
N_2O	2.20E-04	See Note 5	0.26	0.48
CO_2e	118.98	See Note 6	137,841	258,451

1. SO_2 factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1. Sulfuric Acid Mist conservatitvely assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens. Potential Annual Emissions for NO_X and CO based on overall Permit Limit in V-07-0 Condition 3.3.9.

3. Emission factors for filterable and condensable PM from natural gas combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = F_c * U_f * MW_{CO2}
CO_2 emission factor (lb/MMBtu) = 1,040 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

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

Simple Cycle Unit Operating Parameters - Fuel Oil Combustion

Heat Input	1,395	MMBtu/hr, HHV
Turbine Operating Hours	450	hrs/yr

Table C-28. Potential Criteria Pollutant Emissions from Turbine No. 6 Fuel Oil Combustion

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMBtu)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
SO_2	5.04E-02	Note 1	70.23	15.80
NO_X	1.68E-01	Note 2	234.28	160.60
CO	3.80E-02	Note 2	52.99	42.00
Total PM	2.30E-02	Note 1	32.07	7.22
Filterable PM	8.28E-03	Note 3	11.55	2.60
Condensable PM	1.47E-02	Note 3	20.53	4.62
Total PM_{10}	2.30E-02	Note 1	32.07	7.22
Total $PM_{2.5}$	2.30E-02	Note 1	32.07	7.22
VOC	1.49E-02	Note 1	20.78	4.68
Lead[4]	1.40E-05	Note 3	1.95E-02	4.39E-03
Sulfuric Acid Mist (H_2SO_4)	5.04E-03	Note 1	7.02	1.58
GHGs[5,6,7]				
CO_2	162.29	See Note 4	226,314	50,921
CH_4	6.61E-03	See Note 5	9.22	2.08
N_2O	1.32E-03	See Note 5	1.84	0.42
CO_2e	162.85	See Note 6	227,094	51,096

1. Emission factor for SO_2 derived from Equation D-2 in Appendix D to 40 CFR 75.
SO_2 emission factor (lb/MMBtu) = 2.0 * Density (lb/gal) / HHV (MMBtu/gal) * $\%S_{oil}$ / 100.0
SO_2 emission factor (lb/MMBtu) = 2.0 * 7.05 (lb/gal) / 0.140 (MMBtu/gal) * 0.05 (%S) / 100.0
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.

2. Emission factors as provided from Siemens. Potential Annual Emissions for NO_X and CO based on overall Permit Limit in V-07-0 Condition 3.3.9.

3. Emission factors for lead, as well as filterable and condensable PM from fuel oil combustion are estimated from AP-42 Ch. 3.1 Stationary Gas Turbines, Table 3.1-2a (April 2000).

4. Emission factor for CO_2 derived from Equation G-4 in Appendix G to 40 CFR 75.
CO_2 emission factor (lb/MMBtu) = F_c * U_f * MW_{CO2}
CO_2 emission factor (lb/MMBtu) = 1,420 (scf/MMBtu) * 1/385 (scf CO_2/lb-mol) * 44.0 (lb/lb-mol)

5. 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.

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 C-29. Potential Criteria Pollutant Emissions from Combustion Turbine No. 6

Pollutant	Annual Emissions (tpy)
SO_2	16.50
NO_X	160.60
CO	42.00
Total PM	33.86
Filterable PM	10.33
Condensable PM	23.54
Total PM_{10}	33.86
Total $PM_{2.5}$	33.86
VOC	14.64
Lead	4.4E-03
Sulfuric Acid Mist (H_2SO_4)	1.65
GHGs	188,937

Fuel Heater Operating Parameters

Fuel Type	Natural Gas	
Fuel Heating Value	1,020	Btu/scf
No. of Heaters	3	
Operating Hours	8,760	hrs/yr
Maximum Heat Input	6.00	MMBtu/hr, HHV (per unit)

Table C-30. Potential Emissions of Criteria Pollutants from Fuel Heaters (Nos. 1 - 3)

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Hourly Emissions[2] (lb/hr)	Potential Annual Emissions[3] (tpy)
SO_2	5.88E-04	1.1E-02	4.6E-02
NO_X	1.11E-01	1.99	8.71
CO	1.99E-02	0.36	1.57
Total PM	7.45E-03	0.13	0.59
Filterable PM	5.59E-03	0.10	0.44
Condensable PM	1.86E-03	3.4E-02	0.15
Total PM_{10}	7.45E-03	0.13	0.59
Total $PM_{2.5}$	7.45E-03	0.13	0.59
VOC	5.39E-03	0.10	0.43
Lead	4.90E-07	8.8E-06	3.9E-05
Sulfuric Acid Mist (H_2SO_4)	5.88E-05	1.1E-03	4.6E-03
GHGs			
CO_2	116.98	2,106	9,222
CH_4	2.20E-03	4.0E-02	1.7E-01
N_2O	2.20E-04	4.0E-03	1.7E-02
CO_2e	117.10	2,108	9,232

1. See Table C-4 for details on emission factors for Fuel Heaters combusting natural gas.
2. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
3. Potential Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table C-31. Potential Emissions of HAP/TAP from Fuel Heaters (Nos. 1 - 3)

Pollutant	TAP? (Yes/No)	Potential Hourly Emissions[1] (lb/hr)	Potential Annual Emissions[2] (tpy)
2-Methylnaphthalene	No	4.24E-07	1.86E-06
3-Methylchloranthrene	No	3.18E-08	1.39E-07
7,12-Dimethylbenz(a)anthracene	No	2.82E-07	1.24E-06
Acenaphthene	No	3.18E-08	1.39E-07
Acenaphthylene	No	3.18E-08	1.39E-07
Anthracene	No	4.24E-08	1.86E-07
Benzene	Yes	3.71E-05	1.62E-04
Benz(a)anthracene	No	3.18E-08	1.39E-07
Benzo(a)pyrene	No	2.12E-08	9.28E-08
Benzo(b)fluoranthene	No	3.18E-08	1.39E-07
Benzo(g,h,i)perylene	No	2.12E-08	9.28E-08
Benzo(k)fluoranthene	No	3.18E-08	1.39E-07
Chrysene	No	3.18E-08	1.39E-07
Dibenz(a,h)anthracene	No	2.12E-08	9.28E-08
Dichlorobenzene	No	2.12E-05	9.28E-05
Fluoranthene	No	5.29E-08	2.32E-07
Fluorene	No	4.94E-08	2.16E-07
Formaldehyde	Yes	1.32E-03	5.80E-03
Hexane	Yes	3.18E-02	1.39E-01
Indeno(1,2,3-cd)pyrene	No	3.18E-08	1.39E-07
Naphthalene	Yes	1.08E-05	4.71E-05
Phenanthrene	No	3.00E-07	1.31E-06
Pyrene	No	8.82E-08	3.86E-07
Toluene	Yes	6.00E-05	2.63E-04
Arsenic	Yes	3.53E-06	1.55E-05
Beryllium	Yes	2.12E-07	9.28E-07
Cadmium	Yes	1.94E-05	8.50E-05
Chromium	Yes	2.47E-05	1.08E-04
Chromium (VI)	Yes	9.88E-07	4.33E-06
Cobalt	Yes	1.48E-06	6.49E-06
Lead	Yes	See Potential Criteria Pollutant Emissions	
Manganese	Yes	6.71E-06	2.94E-05
Mercury	Yes	4.59E-06	2.01E-05
Nickel	Yes	3.71E-05	1.62E-04
Selenium	Yes	4.24E-07	1.86E-06

1. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Number of Units * Maximum Heat Input (MMBtu/hr)
2. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Hours (hr/yr) / 2,000 (lb/ton)

Simple Cycle Unit Operating Parameters - Natural Gas Combustion

Heat Input Turbines 1 - 4	1,180	MMBtu/hr, HHV (per turbine)
Heat Input Turbines 5 - 6	1,159	MMBtu/hr, HHV (per turbine)
Turbine Operating Hours	3,750	hrs/yr (per turbine)

Table C-32. Potential HAP/TAP Emissions from Turbines Nos. 1 - 6 Natural Gas Combustion

Pollutant	TAP? (Yes/No)	Potential Hourly Emissions[2] (lb/hr)	Potential Emissions[3] (tpy)
1,3-Butadiene	Yes	4.26E-04	7.98E-04
Acetaldehyde	Yes	0.30	0.57
Acrolein	Yes	3.94E-02	0.074
Benzene	Yes	8.02E-02	0.15
Ethylbenzene	Yes	0.16	0.30
Formaldehyde	Yes	0.75	1.41
Naphthalene	Yes	4.45E-03	8.35E-03
PAH	No	3.31E-03	6.21E-03
Propylene Oxide	Yes	0.20	0.38
Toluene	Yes	0.48	0.90
Xylene (Total)	Yes	0.46	0.86

1. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)

2. 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 Turbines 1 - 4	1,365	MMBtu/hr, HHV (per turbine)
Heat Input Turbines 5 - 6	1,395	MMBtu/hr, HHV (per turbine)
Turbine Operating Hours	450	hrs/yr (per turbine)

Table C-33. Potential HAP/TAP Emissions from Turbines Nos. 1 - 6 Fuel Oil Combustion

Pollutant	TAP? (Yes/No)	Potential Hourly Emissions[2] (lb/hr)	Potential Emissions[3] (tpy)
1,3-Butadiene	Yes	1.88	0.42
Acrolein	Yes	1.95	0.44
Benzene	Yes	1.00	0.22
Formaldehyde	Yes	2.61	0.59
Naphthalene	Yes	0.24	5.48E-02
PAH	No	0.28	6.29E-02
Toluene	Yes	1.92	0.43
Xylene (Total)	Yes	1.88	0.42
Arsenic	Yes	3.41E-02	7.67E-03
Beryllium	Yes	2.71E-03	6.09E-04
Cadmium	Yes	2.49E-02	5.61E-03
Chromium	Yes	6.77E-02	1.52E-02
Chromium (VI)	Yes	6.85E-04	1.54E-04
Lead	Yes	See Potential Criteria Pollutant Emissions	
Manganese	Yes	3.56	0.80
Mercury	Yes	5.03E-03	1.13E-03
Nickel	Yes	1.46	0.33
Selenium	Yes	0.10	2.34E-02

1. Potential Emissions (lb/hr) = Emission Factor (lbs/MMBtu) * Heat Input (MMBtu/hr)
2. Pollutant Emissions (tpy) = Potential Hourly Emissions (lb/hr) * Operating Limit (hr/yr) / 2,000 (lb/ton)

Table C-34. Potential HAP/TAP Emissions from Turbines Nos. 1 - 6

Pollutant	TAP? (Yes/No)	Potential Hourly Emissions (lb/hr)	Potential Emissions (tpy)
1,3-Butadiene	Yes	1.88	0.42
Acetaldehyde	Yes	0.30	0.57
Acrolein	Yes	1.95	0.51
Benzene	Yes	1.00	0.37
Ethylbenzene	Yes	0.16	0.30
Formaldehyde	Yes	2.61	2.00
Naphthalene	Yes	2.43E-01	6.31E-02
PAH	No	2.80E-01	6.91E-02
Propylene Oxide	Yes	2.01E-01	0.38
Toluene	Yes	1.92	1.33
Xylene (Total)	Yes	1.88	1.28
Arsenic	Yes	3.41E-02	7.67E-03
Beryllium	Yes	2.71E-03	6.09E-04
Cadmium	Yes	2.49E-02	5.61E-03
Chromium	Yes	6.77E-02	1.52E-02
Chromium (VI)	Yes	6.85E-04	1.54E-04
Lead	Yes	See Potential Criteria Pollutant Emissions	
Manganese	Yes	3.56	0.80
Mercury	Yes	5.03E-03	1.13E-03
Nickel	Yes	1.46	0.33
Selenium	Yes	1.04E-01	2.34E-02

New Fire Pump Operating Parameters - Fuel Oil Combustion

Nameplate	455	hp
	388	kW
Fuel Consumption	23.1	gal/hr
Heat Input Capacity	3.23	MMBtu/hr
Operating Hours	500	hrs/yr

Table C-35. New Fire Pump Potential Emissions

Pollutant	Emission Factor	Emission Factor Unit and Reference	Hourly Emissions[1] (lb/hr)	Annual Emissions[2] (tpy)
SO_2	2.05E-03	(lb/hp-hr), Note 3	0.93	0.23
NO_X	3.58	(g/kW-hr), Note 4	3.06	0.77
CO	2.17	(g/kW-hr), Note 4	1.86	0.46
Total PM	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
Filterable PM	4.61E-02	(g/kW-hr), Note 4,5	0.039	0.010
Condensable PM	2.99E-02	(g/kW-hr), Note 4,5	0.026	0.006
Total PM_{10}	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
Total $PM_{2.5}$	7.60E-02	(g/kW-hr), Note 4	0.065	0.016
VOC	1.30E-01	(g/kW-hr), Note 4	0.11	0.028
Sulfuric Acid Mist (H_2SO_4)	2.05E-04	(lb/hp-hr), Note 3	0.093	0.023
GHGs				
CO_2	163.05	(lb/MMBtu), Note 6	527.31	131.83
CH_4	6.61E-03	(lb/MMBtu), Note 6	2.14E-02	5.35E-03
N_2O	1.32E-03	(lb/MMBtu), Note 6	4.28E-03	1.07E-03
CO_2e	163.61	(lb/MMBtu), Note 7	529.12	132.28

1. Potential Emissions (lb/hr) = Emission Factor * Nameplate Capacity, converted from grams to pounds if necessary
2. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
3. SO_2 emission factor from AP-42 Section 3.3, Gasoline And Diesel Industrial Engines, Table 3.3-1.
Sulfuric Acid Mist conservatively assumed as a portion (10%) of the SO_2 emissions.
4. Emissions data from Caterpillar.
5. Emission factors for filterable and condensable PM are estimated from AP-42 Section 1.3, Fuel Oil Combustion, Table 3.1-2a (April 2000).
6. 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.
7. 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 C-36. New Fire Pump Potential HAP/TAP Emissions

Pollutant	TAP? (Yes/No)	Emission Factor	Emission Factor Unit and Reference	Hourly Emissions[1] (lb/hr)	Annual Emissions[2] (tpy)
Benzene	Yes	9.33E-04	(lb/MMBtu), Note 3	3.02E-03	7.54E-04
Toluene	Yes	4.09E-04	(lb/MMBtu), Note 3	1.32E-03	3.31E-04
Xylene (Total)	Yes	2.85E-04	(lb/MMBtu), Note 3	9.22E-04	2.30E-04
1,3-Butadiene	Yes	3.91E-05	(lb/MMBtu), Note 3	1.26E-04	3.16E-05
Formaldehyde	Yes	1.18E-03	(lb/MMBtu), Note 3	3.82E-03	9.54E-04
Acetaldehyde	Yes	7.67E-04	(lb/MMBtu), Note 3	2.48E-03	6.20E-04
Acrolein	Yes	9.25E-05	(lb/MMBtu), Note 3	2.99E-04	7.48E-05
Naphthalene	Yes	8.48E-05	(lb/MMBtu), Note 3	2.74E-04	6.86E-05

1. Potential Emissions (lb/hr) = Emission Factor * Nameplate Capacity, converted from grams to pounds if necessary
2. Potential Emissions (tpy) = Hourly Emissions (lb/hr) * Hours of Operation (hr/yr) / 2,000 (lb/ton)
3. Emission factors from AP-42 Section 3.3, Gasoline And Diesel Industrial Engines, Table 3.3-2.

New Fuel Oil Storage Tanks Operating Parameters (2 New Tanks)

Storage Components	Ultra Low-Sulfur Diesel	
Max Daily Operating	24	hours/day
Annual Operating Hours	8,760	hours/year
Tank Type	VFRT	
Tank Capacity (each)	1,580,000	gallons
Tank Annual Throughput[1] (each)	8,775,000	gallons/yr

Table C-35. New Fuel Oil Storage Tanks Potential Emissions

Pollutant	HAP? (Yes/No)	TAP? (Yes/No)	Total Losses (lb)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
Fuel Oil Tank No. 2					
VOC	N/A	N/A	944.46	0.11	0.47
Hexane (n-)	Yes	Yes	0.36	4.1E-05	1.8E-04
Benzene	Yes	Yes	1.79	2.0E-04	9.0E-04
Toluene	Yes	Yes	21.47	2.5E-03	1.1E-02
Ethylbenzene	Yes	Yes	2.91	3.3E-04	1.5E-03
Xylene (Total)	Yes	Yes	56.93	6.5E-03	2.8E-02
Naphthalene	Yes	Yes	0.47	5.4E-05	2.4E-04
Benzo(g,h,i)perylene	Yes	No	1.7E-12	1.9E-16	8.5E-16
PACs (Chrysene)	Yes	No	3.2E-10	3.7E-14	1.6E-13
Fuel Oil Tank No. 3					
VOC	N/A	N/A	944.46	0.11	0.47
Hexane (n-)	Yes	Yes	0.36	4.1E-05	1.8E-04
Benzene	Yes	Yes	1.79	2.0E-04	9.0E-04
Toluene	Yes	Yes	21.47	2.5E-03	1.1E-02
Ethylbenzene	Yes	Yes	2.91	3.3E-04	1.5E-03
Xylene (Total)	Yes	Yes	56.93	6.5E-03	2.8E-02
Naphthalene	Yes	Yes	0.47	5.4E-05	2.4E-04
Benzo(g,h,i)perylene	Yes	No	1.7E-12	1.9E-16	8.5E-16
PACs (Chrysene)	Yes	No	3.2E-10	3.7E-14	1.6E-13

1. Tank Annual Throughput (gal/yr) = Sum for Combustion Turbine Nos. 1 - 4 on Fuel Oil
{ Heat Input Capacity (MMBtu/hr) / 0.140 (MMBtu/gal) * Hours of Operation (hr/yr) }

Fixed-Roof Tank Emissions - Monthly

Based on AP-42 (Nov 2019), Section 7.1.3.1.

Tool Last Updated: Mar 2021

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Reporting Year	*2023*

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Tank ID	Enter only Tank ID in this tab.			New Fuel Oil Tank No. 2
Tank Name	Text Description of Tank Name	TK_{name}		
Actual Location		Loc_{Act}		Box Springs, GA
Location for Calculation Purposes		Loc_{Calc}		Columbus, GA
Tank/Roof Type		TK_{roof}		VFR - Cone
Normal Capacity		Cap	gal	1,580,000
Diameter		D	ft	82
Shell Height or Length		H_S	ft	40
Effective Diameter	$= ((H_S * D) / (\pi/4))^{0.5}$ {horiz. tanks only, Eqn. 1-14} = D {all other fixed roof tanks}	D_E	ft	82.0
Effective Height	= π/4 * D {horiz. tanks only, Eqn. 1-15} $= H_S$ -1 {all other fixed roof tanks}	H_E	ft	39.0
External Shell Color		SC_{ext}		Green/Dark
External Shell Paint Condition		PC_{Shell}		New
Roof Color/Shade		RC		Green/Dark
Roof Paint Condition		PC_{Roof}		New
Tank Shell Solar Absorbance		α_{Shell}		0.89
Tank Roof Paint Solar Absorbance		α_{Roof}		0.89
Average Tank Paint Solar Absorbance	$= (\alpha_{Shell} + \alpha_{Roof}) / 2$ {Note A, Table 7.1-6}	α_{Tot}		0.89
Ideal Gas Constant,		R	psia ft^3 / lbmole °R	10.731
Ambient Pressure		P_A	psia	14.490
Used Hs/D Type	Depending on Hs/D type, different equations are used for ter			Default
Hs/D		Hs/D		--

Tank Reference Parameters

Parameter Title	Notes	Parameter Symbol	Units	Value
Underground Tank?		UT		Aboveground
Heated Tank?		HT		No
Liquid Bulk Temperature	Heated Tanks Only	T_B	Degrees F	--
Insulated Tank?		IT		Partial
Pressure Tank?		PT		Atmospheric
Normal Operating Pressure	Only for Pressure Tanks	P_I	psig	0.0
Vapor Tight Roof		VTR		No
Control Device	*= None {No vapor tight roof}* *= User Specified*	CD		None
Control Device Efficiency		CD_{Eff}	%	--
Minimum Liquid Height	Update it to equal to the effective tank height	H_{Ln}	ft	1
Maximum Liquid Height	Update it to equal to the effective tank height	H_{LX}	ft	39
Dome Tank Roof Height	$= R_R - (R_R^2 - (D / 2)^2)^{0.5}$ {dome roof with $D = 2 * R_S$, Eqn. 1-20}	H_R	ft	--
Roof Outage	$= S_R * (D / 2) / 3$ {cone roof, Eqn. 1-17 and 1-18}	H_{RO}	ft	0.9
Breather Vent Pressure Setting	= 0 {No vapor tight roof, Eqn. 1-5 Note 3} = User Specified	P_{BP}	psig	0.00
Breather Vent Vacuum Setting		P_{BV}	psig	0.00
Breather Vent Pressure Setting Range	*= 0 {No vapor tight roof}* *$= P_{BP} - P_{BV}$ {Eqn. 1-10}*	ΔP_B	psig	0.00
Dome Roof Radius	Dome Roofs Only = user input between 0.8 to 1.2 * D {AP-42 7.1-15}	R_R	ft	--
Cone Roof Slope	Cone Roofs Only Default = 0.0625 ft/ft	S_R	ft/ft	0.0625
Tank Working Volume	$= \pi/4 * D_E^2 * (H_{LX} - H_{LN})$ {Eqn. 1-37}	V_{LX}	ft^3	200,679
Days per Year	For leap years, days = 366	t_{yr}	days/yr	365

Emission Summary

Annual Throughput, gal	8,775,000	**Annual Emissions**	0.47
Annual Turnovers	5.84		
Month	**Emissions, lbs**	**Emissions, tons**	
Jan	31.17	0.016	
Feb	37.42	0.019	
Mar	58.43	0.029	
Apr	82.11	0.041	
May	111.07	0.056	
Jun	125.17	0.063	
Jul	138.14	0.069	
Aug	123.54	0.062	
Sep	95.92	0.048	
Oct	66.78	0.033	
Nov	43.83	0.022	
Dec	30.89	0.015	

Note: The emission summary table is pulled into the Tank Emissions tab using cell references A31:B42. The emission summary must remain at this cell reference to function properly.

Calculations					1	2	3	4	5	6	7	8	9	10	11	12
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service					**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Type of Substance	Select Organic Liquid, Petroleum Distillate, or Crude				Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate
Contents of Tank	Select from list (add new compounds in 'VOLs' tab):			= User specified	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2
Speciation Profile	Select from list (add new in 'Speciation Input' tab):			= User specified	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)
Speciation Profile Type				= User specified	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation
Monthly Throughput		Q	gal/month	= User specified	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250
Days-In-Service	Total days per month minus the days tank has a service change, is out of service, or for non-routine events.	t_{IS}	days		31	28	31	30	31	30	31	31	30	31	30	31
Constant in the vapor pressure equation	Used in ΔP_V only for petroleum liquids. If full speciation profile specified, leave blank.	B	°R	= Not Applicable {Organic liquids and full speciation profiles}	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907
Average Liquid Height	Leave blank if unknown. Not applicable for horizontal Tanks. Fill out for tanks operating on level control.	H_L	ft	= User specified if known $= H_{LX} / 2$ {default}	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Liquid Bulk Temperature	Input data through either Tank List tab, or Tank Throughput tab.	$T_{B\text{-input}}$	°F	= specified by user	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Outage		H_{VO}	ft	$= H_S - H_L + H_{RO}$ {all other fixed roof tanks, Eqn. 1-16} $= (H_E / 2)$ {horizontal tanks only}	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Daily Total Solar Insolation Factor		I	Btu / ft^2 day		823	1,079	1,409	1,773	1,936	1,936	1,936	1,718	1,491	1,211	949	753
Vent Setting Correction Factor		K_B		When (P_{BP} > 0.03 psig) and (K_N * (P_{BP} + P_A) / (P_I + P_A)) > 1.0 {Eqn. 1-40} $= (((P_I + P_A) / K_N) - P_{VA,Tla}) / (P_{BP} + P_A - P_{VA,Tla})$ {Eqn. 1-41} Otherwise = 1	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Vapor Space Expansion Factor	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in the tool that tank location is known. True vapor pressure based on liquid stock. If KE < 0, no standing losses occur. Per AP 42, 1> K_E ≥ 0.	K_E		$= (\Delta T_V / (T_{LA} + 459.67 °R)) + ((\Delta P_V - \Delta P_B) / (P_A - P_{VA,Tla})) \geq 0$ { Eqn. 1-5}	0.0516	0.0617	0.0735	0.0851	0.0870	0.0838	0.0831	0.0758	0.0696	0.0637	0.0572	0.0490
Working Loss Turnover (Saturation) Factor	Per Eqn. 1-35, annual threshold for turnovers is 36. Equation modified to a monthly form by converting the monthly turnovers to a theoretical annual turnover equivalent.	K_N		$= (180 + (N * t_{yr} / t_{IS})) / (6 * (N * t_{yr} / t_{IS}))$ {$(N * t_{yr} / t_{IS}) > 36$, Eqn. 1-35} = 1 {$(N * t_{yr} / t_{IS}) \leq 36$, Eqn. 1-35}	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor		K_P		= 0.75 {crude oils, Eqn. 1-35} = 1 {all other organic liquids}	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Vented Vapor Saturation Factor	Constant 0.053 has units of 1/(psia-ft). True vapor pressure based on liquid surface temperature.	K_S		$= 1 / (1 + 0.053 * P_{VA,Tla} * H_{VO})$ {Eqn. 1-21}	0.995	0.994	0.992	0.989	0.986	0.983	0.982	0.982	0.985	0.990	0.993	0.995
Vapor Molecular Weight	When using full speciation profiles, calculated as the weighted average of the M_V of each component.	M_V	lb/lb-mole	= VOL data of tank contents {partial speciation} $M_V = \Sigma (M_{Vi} * (P_{VA,Tla\text{-}i}/P_{VA,Tla}))$ {full speciation, Eqn. 1-23} $M_L = 1 / \Sigma (Z_{Li} / M_{Li})$ {full speciation}	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Liquid Molecular Weight		M_L	lb/lb-mole		188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Number of Turnovers per Month	Constant 5.614 has units of ft^3/bbl.	N		$= 5.614 * Q * (bbl / 42 gal) / V_{LX}$ (Eqn. 1-36} and {Eqn. 1-37}	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Average Daily Minimum Ambient Temperature		T_{AN}	°F		38.00	40.40	46.60	53.50	62.90	70.10	73.20	72.70	67.30	56.20	45.90	39.10
Average Daily Maximum Ambient Temperature		T_{AX}	°F		57.40	61.20	68.70	76.00	83.40	88.50	91.30	90.40	85.50	76.40	67.20	58.40
Daily Average Ambient Temperature		T_{AA}	°F	$= (T_{AX} + T_{AN}) / 2$ {Eqn. 1-30}	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Minimum Liquid Surf. Temperature, F		T_{LN}	°F	$= T_{LA} - 0.25 * \Delta T_V$ {Fig. 7.1-17}	44.79	47.68	54.34	61.38	70.08	76.54	79.54	78.90	73.67	63.27	53.36	45.86
Daily Maximum Liquid Surf. Temperature, F		T_{LX}	°F	$= T_{LA} + 0.25 * \Delta T_V$ {Fig. 7.1-17}	57.93	63.52	73.51	83.90	93.46	99.29	102.20	99.50	92.40	80.11	68.19	58.35
Daily Vapor Temperature Range	Constant 0.028 has units of (°R-ft^2-day/Btu)	ΔT_V	°R	For fully insulated tanks = 0 For uninsulated tanks: If default Hs/D = 0.7 * (TAX - TAN) + 0.02 * αTot * I {Eqn. 1-7} If specific Hs/D = [1 – 0.8 / (2.2 Hs/D + 1.9)] (TAX – TAN) + [0.042 αRI + 0.026 (Hs/D) αSI] / (2.2 Hs/D + 1.9) {Eqn. 1-6} For partial insulated tanks: = 0.6 * (TAX - TAN) + 0.02 * αR * I {Eqn. 1-8}	26.29	31.69	38.34	45.06	46.76	45.50	45.32	41.20	37.46	33.68	29.67	24.98

Calculations																
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service					**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Daily Average Liquid Surf. Temperature	Constant 0.0079 has units of (°R-ft^2-day/btu).	T_{LA}	°F	For fully insulated tanks = T_B For partial insulated tanks = 0.3 * T_{AA} + 0.7 * T_B + 0.005 * α_R * I {Eqn. 1-29} For uninsulated tanks = 0.4 * T_{AA} + 0.6 * T_B + 0.005 * α_{Tot} * I {Eqn. 1-28} for default Hs/D = (0.5 - 0.8/(4.4Hs/D + 3.8)) T_{AA} + (0.5 + 0.8/(4.4Hs/D+3.8)) * T_B + (0.021α_RI + 0.013(Hs/D)α_SI)/(4.4Hs/D+3.8) {Eqn. 1-27} for specific Hs/D	51.36	55.60	63.92	72.64	81.77	87.92	90.87	89.20	83.03	71.69	60.77	52.10
Liquid Bulk Temperature	If T_B is unknown, see AP-42 7.1 Eqn 1-27 Note 5.	T_B	°F	= specified by user {Insulated tanks only} = T_{AA} + 0.003 * α_{Tot} * I {Eqn. 1-31}	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Average Vapor Space Temperature	It is a new parameter in the new version of AP 42	T_V	°F	For fully insulated tanks = TB For partial insulated tanks = 0.6 * TAA + 0.4 * TB + 0.01 * αR * I {Eqn. 1-34} For uninsulated tanks If default Hs/D = 0.7 TAA + 0.3 TB + 0.009 α I {Eqn. 1-33} If specific Hs/D = [(2.2 Hs/D + 1.1) TAA + 0.8 TB + 0.021 αRI + 0.013 (Hs/D) αSI] / [2.2 Hs/D + 1.9] {Eqn. 1-32}	55.02	60.40	70.19	80.53	90.38	96.53	99.48	96.84	89.67	77.08	65.00	55.45
Vapor Pressure at Daily Av. Liquid Surf. Temp.	Used for speciated emissions and most vapor pressures. $P_{VA,Tla}$ uses T_{LA}.	$P_{VA,Tla}$	psia	*{full speciation profiles, Eqn. 1-24}:* Sum of partial true vapor pressures components. *{partial/no speciation profiles}: Calculated* vapor pressures at T (°F) with provided coefficients or interpolated with provided vapor pressures at different temperatures.	0.0049	0.0056	0.0074	0.0097	0.0129	0.0155	0.0169	0.0161	0.0134	0.0095	0.0066	0.0050
Vapor Pressure at Daily Min. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VN} uses T_{LN}.	P_{VN}	psia		0.0039	0.0043	0.0054	0.0068	0.0090	0.0110	0.0121	0.0118	0.0101	0.0072	0.0052	0.0040
Vapor Pressure at Daily Max. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VX} uses T_{LX}.	P_{VX}	psia		0.0061	0.0073	0.0100	0.0138	0.0183	0.0216	0.0235	0.0218	0.0177	0.0123	0.0085	0.0061
Daily Vapor Pressure Range		ΔP_V	psia	= P_{VX} - P_{VN} {Eqn. 1-9}	0.002	0.003	0.005	0.007	0.009	0.011	0.011	0.010	0.008	0.005	0.003	0.002
Vapor Density		W_V	lb/ft^3	= (M_V * $P_{VA,Tla}$) / (R * (T_{LA} + 459.67 °R)) {Eqn. 1-21}	0.0001142	0.0001304	0.0001685	0.0002184	0.0002843	0.0003383	0.0003671	0.0003511	0.0002959	0.0002133	0.0001535	0.0001170
Vapor Space Volume		V_V	ft^3	= (π/4 * D_E^2) * H_{VO} {Eqn. 1-3}	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131
Heating Cycle																
Heating Cycle Period (days)	How many days in one heating cy	$Days_H$	days		--	--	--	--	--	--	--	--	--	--	--	--
Max Liquid Bulk Temperature	Highest liquid temperature in one heating cycle.	T_{BX}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Min Liquid Bulk Temperature	Lowest liquid temperature in one heating cycle.	T_{BN}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Average Liquid Bulk Temperature	Average liquid temperature in one heating cycle.	T_{BA}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Vapor Temperature Range		ΔT_{V-H}	°R	= T_{BX} - T_{BN} {Eqn. 8-1}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Pressure Range		ΔP_{V-H}	psi	=P_{VX} - P_{VN} = P_{BX} - P_{BN} {Eqn. 1-9}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Expansion Factor from Heating Cycle	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in	K_{E-H}		= (ΔT_{V-H} / (T_{LA} + 459.67 °R)) + ((ΔP_{V-H} - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}	--	--	--	--	--	--	--	--	--	--	--	--
Standing Storage Loss	Uncontrolled emissions. No standing or breathing losses occur for underground tanks per AP-42 Eqn. 7.1-15.	L_S	lbs/month	= 0 {underground tanks only} = t_{IS} * V_V * W_V * K_E * K_S {Eqn. 1-2}	20.0080	24.6656	41.9653	60.7694	83.2746	92.1042	102.2531	89.2206	67.0003	45.9270	28.8223	19.4527
Standing Storage Loss from Heating Cycles	Uncontrolled emissions. Standing losses occur when there is heating cycle for fully insulated tanks, Per AP-42 Section 7.1.3.8.4	L_{S-H}	lbs/month	= 0 {no heating cycle} = t_{IS-H} * V_V * W_V * K_{E-H} * K_S {Eqn. 1-2}	--	--	--	--	--	--	--	--	--	--	--	--
Working Loss	Uncontrolled emissions. True vapor pressure based on liquid surface.	L_W	lbs/month	= Q * (5.614 ft^3/bbl) * (bbl / 42 gal) * W_V * K_N * K_P * K_B {Eqn. 1-35}	11.16	12.75	16.47	21.35	27.79	33.06	35.88	34.32	28.92	20.85	15.01	11.44
Total Losses	**Uncontrolled emissions.**	L_T	**lbs/month**	**= (L_S + L_W) {Eqn. 1-1}**	**31.17**	**37.42**	**58.43**	**82.11**	**111.07**	**125.17**	**138.14**	**123.54**	**95.92**	**66.78**	**43.83**	**30.89**

Speciated Component Emissions	Species ID	Controlled with Carbon Adsorpti	Annual Emissions	Controlled Monthly Emissions ($L_{T,CD-i}$ lb/month) $= (P_{VA,Tla-i} * M_{V-i} / (P_{VA,Tla} * M_V) * (1 - CD_{eff})) * L_T$											
Component Name			lb/yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hexane (n-)	1	--	0.36	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.04	0.03	0.03	0.02	0.01
Benzene	2	--	1.79	0.07	0.08	0.12	0.16	0.21	0.23	0.25	0.22	0.18	0.13	0.09	0.07
Trimethylpentane (2,3,4)	3	--	0.00												
Toluene	4	--	21.47	0.75	0.89	1.37	1.89	2.51	2.79	3.05	2.74	2.16	1.54	1.03	0.74
Ethylbenzene	5	--	2.91	0.09	0.11	0.18	0.25	0.34	0.39	0.43	0.39	0.30	0.20	0.13	0.09
Xylene (m-)	6	--	56.93	1.79	2.17	3.44	4.92	6.74	7.66	8.48	7.57	5.83	3.99	2.57	1.77
Isopropyl benzene {cumene}	7	--	0.00												
MTBE {Methyl tert-butyl ether}	8	--	0.00												
Trimethylbenzene (1,2,4)	9	--	48.41	1.33	1.65	2.74	4.07	5.82	6.78	7.60	6.74	5.06	3.29	2.01	1.33
Cyclohexane	10	--	0.00												
Gasoline (RVP 13)	11	--	0.00												
Ethanol {ethyl alcohol}	12	--	0.00												
Acetaldehyde	13	--	0.00												
Heptane (n-)	14	--	0.00												
Isopentane {2-methylbutane}	15	--	0.00												
Pentane (n-)	16	--	0.00												
Butane	17	--	0.00												
Naphthalene	18	--	0.47	0.01	0.01	0.02	0.04	0.06	0.07	0.08	0.07	0.05	0.03	0.02	0.01
Benzo(g,h,i)perylene	19	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PACs (Chrysene)	20	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
--	21	--													

Fixed-Roof Tank Emissions - Monthly

Based on AP-42 (Nov 2019), Section 7.1.3.1.
Tool Last Updated: Mar 2021

Click Here to Go Back to Cover Page

Reporting Year	2023

Tank Reference Parameters				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Value**
Tank ID	Enter only Tank ID in this tab.			New Fuel Oil Tank No. 3
Tank Name	Text Description of Tank Name	TK_{name}		
Actual Location		Loc_{Act}		Box Springs, GA
Location for Calculation Purposes		Loc_{Calc}		Columbus, GA
Tank/Roof Type		TK_{roof}		VFR - Cone
Normal Capacity		Cap	gal	1,580,000
Diameter		D	ft	82
Shell Height or Length		H_S	ft	40
Effective Diameter	$= ((H_S * D) / (\pi/4))^{0.5}$ {horiz. tanks only, Eqn. 1-14} = D {all other fixed roof tanks}	D_E	ft	82.0
Effective Height	= π/4 * D {horiz. tanks only, Eqn. 1-15} $= H_S - 1$ {all other fixed roof tanks}	H_E	ft	39.0
External Shell Color		SC_{ext}		Green/Dark
External Shell Paint Condition		PC_{Shell}		New
Roof Color/Shade		RC		Green/Dark
Roof Paint Condition		PC_{Roof}		New
Tank Shell Solar Absorbance		α_{Shell}		0.89
Tank Roof Paint Solar Absorbance		α_{Roof}		0.89
Average Tank Paint Solar Absorbance	$= (\alpha_{Shell} + \alpha_{Roof}) / 2$ {Note A, Table 7.1-6}	α_{Tot}		0.89
Ideal Gas Constant,		R	psia ft³ / lbmole °R	10.731
Ambient Pressure		P_A	psia	14.490
Used Hs/D Type	Depending on Hs/D type, different equations are used for ter			Default
Hs/D		Hs/D		--

Tank Reference Parameters				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Value**
Underground Tank?		UT		Aboveground
Heated Tank?		HT		No
Liquid Bulk Temperature	Heated Tanks Only	T_B	Degrees F	--
Insulated Tank?		IT		Partial
Pressure Tank?		PT		Atmospheric
Normal Operating Pressure	Only for Pressure Tanks	P_I	psig	0.0
Vapor Tight Roof		VTR		No
Control Device	*= None {No vapor tight roof}* *= User Specified*	CD		None
Control Device Efficiency		CD_{Eff}	%	--
Minimum Liquid Height	Update it to equal to the effective tank height	H_{Ln}	ft	1
Maximum Liquid Height	Update it to equal to the effective tank height	H_{LX}	ft	39
Dome Tank Roof Height	$= R_R - (R_R^2 - (D / 2)^2)^{0.5}$ {dome roof with $D = 2 * R_S$, Eqn. 1-20}	H_R	ft	--
Roof Outage	$= S_R * (D / 2) / 3$ {cone roof, Eqn. 1-17 and 1-18}	H_{RO}	ft	0.9
Breather Vent Pressure Setting	= 0 {No vapor tight roof, Eqn. 1-5 Note 3} = User Specified	P_{BP}	psig	0.00
Breather Vent Vacuum Setting		P_{BV}	psig	0.00
Breather Vent Pressure Setting Range	*= 0 {No vapor tight roof}* $= P_{BP} - P_{BV}$ *{Eqn. 1-10}*	ΔP_B	psig	0.00
Dome Roof Radius	Dome Roofs Only = user input between 0.8 to 1.2 * D {AP-42 7.1-15}	R_R	ft	--
Cone Roof Slope	Cone Roofs Only Default = 0.0625 ft/ft	S_R	ft/ft	0.0625
Tank Working Volume	$= \pi/4 * D_E^2 * (H_{LX} - H_{LN})$ {Eqn. 1-37}	V_{LX}	ft^3	200,679
Days per Year	For leap years, days = 366	t_{yr}	days/yr	365

Emission Summary			
Annual Throughput, gal	8,775,000	**Annual Emissions** 0.47	Note: The emission summary table is pulled into the Tank Emissions tab using cell references A31:B42. The emission summary must remain at this cell reference to function properly.
Annual Turnovers	5.84		
Month	**Emissions, lbs**	**Emissions, tons**	
Jan	31.17	0.016	
Feb	37.42	0.019	
Mar	58.43	0.029	
Apr	82.11	0.041	
May	111.07	0.056	
Jun	125.17	0.063	
Jul	138.14	0.069	
Aug	123.54	0.062	
Sep	95.92	0.048	
Oct	66.78	0.033	
Nov	43.83	0.022	
Dec	30.89	0.015	

Calculations				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**
Service				
Type of Substance	Select Organic Liquid, Petroleum Distillate, or Crude			
Contents of Tank	Select from list (add new compounds in 'VOLs' tab):			= User specified
Speciation Profile	Select from list (add new in 'Speciation Input' tab):			= User specified
Speciation Profile Type				= User specified
Monthly Throughput		Q	gal/month	= User specified
Days-In-Service	Total days per month minus the days tank has a service change, is out of service, or for non-routine events.	t_{IS}	days	
Constant in the vapor pressure equation	Used in ΔP_V only for petroleum liquids. If full speciation profile specified, leave blank.	B	°R	= Not Applicable {Organic liquids and full speciation profiles}
Average Liquid Height	Leave blank if unknown. Not applicable for horizontal Tanks. Fill out for tanks operating on level control.	H_L	ft	= User specified if known = H_{LX} / 2 {default}
Liquid Bulk Temperature	Input data through either Tank List tab, or Tank Throughput tab.	$T_{B\text{-input}}$	°F	= specified by user
Vapor Space Outage		H_{VO}	ft	= H_S - H_L + H_{RO} {all other fixed roof tanks, Eqn. 1-16} = (H_E / 2) {horizontal tanks only}
Daily Total Solar Insolation Factor		I	Btu / ft^2 day	
Vent Setting Correction Factor		K_B		When (P_{BP} > 0.03 psig) and (K_N (P_{BP} + P_A) / (P_I + P_A)) > 1.0 {Eqn. 1-40} = (((P_I + P_A) / K_N) - $P_{VA,Tla}$) / (P_{BP} + P_A - $P_{VA,Tla}$) {Eqn. 1-41} Otherwise = 1
Vapor Space Expansion Factor	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in the tool that tank location is known. True vapor pressure based on liquid stock. If KE < 0, no standing losses occur. Per AP 42, 1> K_E ≥ 0.	K_E		= (ΔT_V / (T_{LA} + 459.67 °R)) + ((ΔP_V - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}
Working Loss Turnover (Saturation) Factor	Per Eqn. 1-35, annual threshold for turnovers is 36. Equation modified to a monthly form by converting the monthly turnovers to a theoretical annual turnover equivalent.	K_N		= (180 + (N * t_{yr} / t_{IS})) / (6 * (N * t_{yr} / t_{IS})) {(N * t_{yr} / t_{IS}) > 36, Eqn. 1-35} = 1 {(N * t_{yr} / t_{IS}) ≤ 36, Eqn. 1-35}
Working Loss Product Factor		K_P		= 0.75 {crude oils, Eqn. 1-35} = 1 {all other organic liquids}
Vented Vapor Saturation Factor	Constant 0.053 has units of 1/(psia-ft). True vapor pressure based on liquid surface temperature.	K_S		= 1 / (1 + 0.053 * $P_{VA,Tla}$ * H_{VO}) {Eqn. 1-21}
Vapor Molecular Weight	When using full speciation profiles, calculated as the weighted average of the M_V of each component.	M_V	lb/lb-mole	= VOL data of tank contents {partial speciation} M_V = Σ (M_{Vi} * ($P_{VA,Tla\text{-}i}$/$P_{VA,Tla}$)) {full speciation, Eqn. 1-23}
Liquid Molecular Weight		M_L	lb/lb-mole	M_L = 1 / Σ (Z_{Li} / M_{Li}) {full speciation}
Number of Turnovers per Month	Constant 5.614 has units of ft^3/bbl.	N		= 5.614 * Q * (bbl / 42 gal) / V_{LX} (Eqn. 1-36} and {Eqn. 1-37}
Average Daily Minimum Ambient Temperature		T_{AN}	°F	
Average Daily Maximum Ambient Temperature		T_{AX}	°F	
Daily Average Ambient Temperature		T_{AA}	°F	= (T_{AX} + T_{AN}) / 2 {Eqn. 1-30}
Daily Minimum Liquid Surf. Temperature, F		T_{LN}	°F	= T_{LA} - 0.25 * ΔT_V {Fig. 7.1-17}
Daily Maximum Liquid Surf. Temperature, F		T_{LX}	°F	= T_{LA} + 0.25 * ΔT_V {Fig. 7.1-17}
Daily Vapor Temperature Range	Constant 0.028 has units of (°R-ft^2-day/Btu)	ΔT_V	°R	For fully insulated tanks = 0 For uninsulated tanks: If default Hs/D = 0.7 * (TAX - TAN) + 0.02 * αTot * I {Eqn. 1-7} If specific Hs/D = [1 – 0.8 / (2.2 Hs/D + 1.9)] (TAX – TAN) + [0.042 αRI + 0.026 (Hs/D) αSI] / (2.2 Hs/D + 1.9) {Eqn. 1-6} For partial insulated tanks: = 0.6 * (TAX - TAN) + 0.02 * αR * I {Eqn. 1-8}

Parameter Title	1	2	3	4	5	6	7	8	9	10	11	12
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Type of Substance	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate
Contents of Tank	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2
Speciation Profile	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)
Speciation Profile Type	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation
Monthly Throughput	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250	731,250
Days-In-Service	31	28	31	30	31	30	31	31	30	31	30	31
Constant in the vapor pressure equation	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907
Average Liquid Height	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Outage	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Daily Total Solar Insolation Factor	823	1,079	1,409	1,773	1,936	1,936	1,936	1,718	1,491	1,211	949	753
Vent Setting Correction Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Vapor Space Expansion Factor	0.0516	0.0617	0.0735	0.0851	0.0870	0.0838	0.0831	0.0758	0.0696	0.0637	0.0572	0.0490
Working Loss Turnover (Saturation) Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Vented Vapor Saturation Factor	0.995	0.994	0.992	0.989	0.986	0.983	0.982	0.982	0.985	0.990	0.993	0.995
Vapor Molecular Weight	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Liquid Molecular Weight	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Number of Turnovers per Month	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Average Daily Minimum Ambient Temperature	38.00	40.40	46.60	53.50	62.90	70.10	73.20	72.70	67.30	56.20	45.90	39.10
Average Daily Maximum Ambient Temperature	57.40	61.20	68.70	76.00	83.40	88.50	91.30	90.40	85.50	76.40	67.20	58.40
Daily Average Ambient Temperature	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Minimum Liquid Surf. Temperature, F	44.79	47.68	54.34	61.38	70.08	76.54	79.54	78.90	73.67	63.27	53.36	45.86
Daily Maximum Liquid Surf. Temperature, F	57.93	63.52	73.51	83.90	93.46	99.29	102.20	99.50	92.40	80.11	68.19	58.35
Daily Vapor Temperature Range	26.29	31.69	38.34	45.06	46.76	45.50	45.32	41.20	37.46	33.68	29.67	24.98

Calculations

Parameter Title	Notes	Parameter Symbol	Units	Reference or Equation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Service					**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Daily Average Liquid Surf. Temperature	Constant 0.0079 has units of (°R-ft^2-day/btu).	T_{LA}	°F	For fully insulated tanks = T_B For partial insulated tanks = 0.3 * T_{AA} + 0.7 * T_B + 0.005 * α_R * I {Eqn. 1-29} For uninsulated tanks = 0.4 * T_{AA} + 0.6 * T_B + 0.005 * α_{Tot} * I {Eqn. 1-28} for default Hs/D = (0.5 - 0.8/(4.4Hs/D + 3.8)) T_{AA} + (0.5 + 0.8/(4.4Hs/D+3.8)) * T_B + (0.021α_RI + 0.013(Hs/D)α_SI)/(4.4Hs/D+3.8) {Eqn. 1-27} for specific Hs/D	51.36	55.60	63.92	72.64	81.77	87.92	90.87	89.20	83.03	71.69	60.77	52.10
Liquid Bulk Temperature	If T_B is unknown, see AP-42 7.1 Eqn 1-27 Note 5.	T_B	°F	= specified by user {Insulated tanks only} = T_{AA} + 0.003 * α_{Tot} * I {Eqn. 1-31}	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Average Vapor Space Temperature	It is a new parameter in the new version of AP 42	T_V	°F	For fully insulated tanks = TB For partial insulated tanks = 0.6 * TAA + 0.4 * TB + 0.01 * αR * I {Eqn. 1-34} For uninsulated tanks If default Hs/D = 0.7 TAA + 0.3 TB + 0.009 α I {Eqn. 1-33} If specific Hs/D = [(2.2 Hs/D + 1.1) TAA + 0.8 TB + 0.021 αRI + 0.013 (Hs/D) αSI] / [2.2 Hs/D + 1.9] {Eqn. 1-32}	55.02	60.40	70.19	80.53	90.38	96.53	99.48	96.84	89.67	77.08	65.00	55.45
Vapor Pressure at Daily Av. Liquid Surf. Temp.	Used for speciated emissions and most vapor pressures. $P_{VA,Tla}$ uses T_{LA}.	$P_{VA,Tla}$	psia	*{full speciation profiles, Eqn. 1-24}:* Sum of partial true vapor pressures components. *{partial/no speciation profiles}: Calculated* vapor pressures at T (°F) with provided coefficients or interpolated with provided vapor pressures at different temperatures.	0.0049	0.0056	0.0074	0.0097	0.0129	0.0155	0.0169	0.0161	0.0134	0.0095	0.0066	0.0050
Vapor Pressure at Daily Min. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VN} uses T_{LN}.	P_{VN}	psia		0.0039	0.0043	0.0054	0.0068	0.0090	0.0110	0.0121	0.0118	0.0101	0.0072	0.0052	0.0040
Vapor Pressure at Daily Max. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VX} uses T_{LX}.	P_{VX}	psia		0.0061	0.0073	0.0100	0.0138	0.0183	0.0216	0.0235	0.0218	0.0177	0.0123	0.0085	0.0061
Daily Vapor Pressure Range		ΔP_V	psia	= P_{VX} - P_{VN} {Eqn. 1-9}	0.002	0.003	0.005	0.007	0.009	0.011	0.011	0.010	0.008	0.005	0.003	0.002
Vapor Density		W_V	lb/ft^3	= (M_V * $P_{VA,Tla}$) / (R * (T_{LA} + 459.67 °R)) {Eqn. 1-21}	0.0001142	0.0001304	0.0001685	0.0002184	0.0002843	0.0003383	0.0003671	0.0003511	0.0002959	0.0002133	0.0001535	0.0001170
Vapor Space Volume		V_V	ft^3	= (π/4 * D_E^2) * H_{VO} {Eqn. 1-3}	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131	110,131
Heating Cycle																
Heating Cycle Period (days)	How many days in one heating cy	$Days_H$	days		--	--	--	--	--	--	--	--	--	--	--	--
Max Liquid Bulk Temperature	Highest liquid temperature in one heating cycle.	T_{BX}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Min Liquid Bulk Temperature	Lowest liquid temperature in one heating cycle.	T_{BN}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Average Liquid Bulk Temperature	Average liquid temperature in one heating cycle.	T_{BA}	°F		--	--	--	--	--	--	--	--	--	--	--	--
Vapor Temperature Range		ΔT_{V-H}	°R	= T_{BX} - T_{BN} {Eqn. 8-1}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Pressure Range		ΔP_{V-H}	psi	=P_{VX} - P_{VN} = P_{BX} - P_{BN} {Eqn. 1-9}	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Expansion Factor from Heating Cycle	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in	K_{E-H}		= (ΔT_{V-H} / (T_{LA} + 459.67 °R)) + ((ΔP_{V-H} - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}	--	--	--	--	--	--	--	--	--	--	--	--
Standing Storage Loss	Uncontrolled emissions. No standing or breathing losses occur for underground tanks per AP-42 Eqn. 7.1-15.	L_S	lbs/month	= 0 {underground tanks only} = t_{IS} * V_V * W_V * K_E * K_S {Eqn. 1-2}	20.0080	24.6656	41.9653	60.7694	83.2746	92.1042	102.2531	89.2206	67.0003	45.9270	28.8223	19.4527
Standing Storage Loss from Heating Cycles	Uncontrolled emissions. Standing losses occur when there is heating cycle for fully insulated tanks, Per AP-42 Section 7.1.3.8.4	L_{S-H}	lbs/month	= 0 {no heating cycle} = t_{IS-H} * V_V * W_V * K_{E-H} * K_S {Eqn. 1-2}	--	--	--	--	--	--	--	--	--	--	--	--
Working Loss	Uncontrolled emissions. True vapor pressure based on liquid surface.	L_W	lbs/month	= Q * (5.614 ft^3/bbl) * (bbl / 42 gal) * W_V * K_N * K_P * K_B {Eqn. 1-35}	11.16	12.75	16.47	21.35	27.79	33.06	35.88	34.32	28.92	20.85	15.01	11.44
Total Losses	**Uncontrolled emissions.**	L_T	**lbs/month**	**= (L_S + L_W) {Eqn. 1-1}**	**31.17**	**37.42**	**58.43**	**82.11**	**111.07**	**125.17**	**138.14**	**123.54**	**95.92**	**66.78**	**43.83**	**30.89**

Speciated Component Emissions	Species ID	Controlled with Carbon Adsorpti	Annual Emissions	Controlled Monthly Emissions ($L_{T,CD-i}$ lb/month) $= (P_{VA,Tla-i} * M_{V-i} / (P_{VA,Tla} * M_V) * (1 - CD_{eff})) * L_T$											
Component Name			**lb/yr**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Hexane (n-)	1	--	0.36	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.04	0.03	0.03	0.02	0.01
Benzene	2	--	1.79	0.07	0.08	0.12	0.16	0.21	0.23	0.25	0.22	0.18	0.13	0.09	0.07
Trimethylpentane (2,3,4)	3	--	0.00												
Toluene	4	--	21.47	0.75	0.89	1.37	1.89	2.51	2.79	3.05	2.74	2.16	1.54	1.03	0.74
Ethylbenzene	5	--	2.91	0.09	0.11	0.18	0.25	0.34	0.39	0.43	0.39	0.30	0.20	0.13	0.09
Xylene (m-)	6	--	56.93	1.79	2.17	3.44	4.92	6.74	7.66	8.48	7.57	5.83	3.99	2.57	1.77
Isopropyl benzene {cumene}	7	--	0.00												
MTBE {Methyl tert-butyl ether}	8	--	0.00												
Trimethylbenzene (1,2,4)	9	--	48.41	1.33	1.65	2.74	4.07	5.82	6.78	7.60	6.74	5.06	3.29	2.01	1.33
Cyclohexane	10	--	0.00												
Gasoline (RVP 13)	11	--	0.00												
Ethanol {ethyl alcohol}	12	--	0.00												
Acetaldehyde	13	--	0.00												
Heptane (n-)	14	--	0.00												
Isopentane {2-methylbutane}	15	--	0.00												
Pentane (n-)	16	--	0.00												
Butane	17	--	0.00												
Naphthalene	18	--	0.47	0.01	0.01	0.02	0.04	0.06	0.07	0.08	0.07	0.05	0.03	0.02	0.01
Benzo(g,h,i)perylene	19	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PACs (Chrysene)	20	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
--	21	--													

Existing Fuel Oil Storage Tank Operating Parameters

Storage Components	Low-Sulfur Diesel	
Max Daily Operating	24	hours/day
Annual Operating Hours	8,760	hours/year
Tank Type	VFRT	
Tank Capacity	1,200,000	gallons
Tank Annual Throughput[1]	8,921,500	gallons/yr

Table C-36. Existing Fuel Oil Storage Tank Potential Emissions

Pollutant	HAP? (Yes/No)	TAP? (Yes/No)	Total Losses (lb)	Potential Hourly Emissions (lb/hr)	Potential Annual Emissions (tpy)
VOC	N/A	N/A	789.75	0.09	0.39
Hexane (n-)	Yes	Yes	0.30	3.4E-05	1.5E-04
Benzene	Yes	Yes	1.50	1.7E-04	7.5E-04
Toluene	Yes	Yes	17.95	2.0E-03	9.0E-03
Ethylbenzene	Yes	Yes	2.44	2.8E-04	1.2E-03
Xylene (Total)	Yes	Yes	47.61	5.4E-03	2.4E-02
Naphthalene	Yes	Yes	0.39	4.5E-05	2.0E-04
Benzo(g,h,i)perylene	Yes	No	1.4E-12	1.6E-16	7.1E-16
PACs (Chrysene)	Yes	No	2.7E-10	3.1E-14	1.3E-13

1. Tank annual throughput based on historical permitting.

Fixed-Roof Tank Emissions - Monthly

Based on AP-42 (Nov 2019), Section 7.1.3.1.

Tool Last Updated: Mar 2021

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Reporting Year	*2023*

Tank Reference Parameters				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Value**
Tank ID	Enter only Tank ID in this tab.			Existing Fuel Oil Tank No. 1
Tank Name	Text Description of Tank Name	TK_{name}		
Actual Location		Loc_{Act}		Box Springs, GA
Location for Calculation Purposes		Loc_{Calc}		Columbus, GA
Tank/Roof Type		TK_{roof}		VFR - Cone
Normal Capacity		Cap	gal	1,200,000
Diameter		D	ft	72.33
Shell Height or Length		H_S	ft	39
Effective Diameter	$= ((H_S * D) / (\pi/4))^{0.5}$ {horiz. tanks only, Eqn. 1-14} = D {all other fixed roof tanks}	D_E	ft	72.3
Effective Height	= π/4 * D {horiz. tanks only, Eqn. 1-15} $= H_S - 1$ {all other fixed roof tanks}	H_E	ft	38.0
External Shell Color		SC_{ext}		Green/Dark
External Shell Paint Condition		PC_{Shell}		Average
Roof Color/Shade		RC		Green/Dark
Roof Paint Condition		PC_{Roof}		Average
Tank Shell Solar Absorbance		α_{Shell}		0.90
Tank Roof Paint Solar Absorbance		α_{Roof}		0.90
Average Tank Paint Solar Absorbance	$= (\alpha_{Shell} + \alpha_{Roof}) / 2$ {Note A, Table 7.1-6}	α_{Tot}		0.90
Ideal Gas Constant,		R	psia ft³ / lbmole °R	10.731
Ambient Pressure		P_A	psia	14.490
Used Hs/D Type	Depending on Hs/D type, different equations are used for ter			Default
Hs/D		Hs/D		--

Tank Reference Parameters				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Value**
Underground Tank?		UT		Aboveground
Heated Tank?		HT		No
Liquid Bulk Temperature	Heated Tanks Only	T_B	Degrees F	--
Insulated Tank?		IT		Partial
Pressure Tank?		PT		Atmospheric
Normal Operating Pressure	Only for Pressure Tanks	P_I	psig	0.0
Vapor Tight Roof		VTR		No
Control Device	*= None {No vapor tight roof}* *= User Specified*	CD		None
Control Device Efficiency		CD_{Eff}	%	--
Minimum Liquid Height	Update it to equal to the effective tank height	H_{Ln}	ft	1
Maximum Liquid Height	Update it to equal to the effective tank height	H_{LX}	ft	38
Dome Tank Roof Height	$= R_R - (R_R^2 - (D / 2)^2)^{0.5}$ {dome roof with $D = 2 * R_S$, Eqn. 1-20}	H_R	ft	--
Roof Outage	$= S_R * (D / 2) / 3$ {cone roof, Eqn. 1-17 and 1-18}	H_{RO}	ft	0.8
Breather Vent Pressure Setting	= 0 {No vapor tight roof, Eqn. 1-5 Note 3} = User Specified	P_{BP}	psig	0.00
Breather Vent Vacuum Setting		P_{BV}	psig	0.00
Breather Vent Pressure Setting Range	*= 0 {No vapor tight roof}* $= P_{BP} - P_{BV}$ *{Eqn. 1-10}*	ΔP_B	psig	0.00
Dome Roof Radius	Dome Roofs Only = user input between 0.8 to 1.2 * D {AP-42 7.1-15}	R_R	ft	--
Cone Roof Slope	Cone Roofs Only Default = 0.0625 ft/ft	S_R	ft/ft	0.0625
Tank Working Volume	$= \pi/4 * D_E^2 * (H_{LX} - H_{LN})$ {Eqn. 1-37}	V_{LX}	ft^3	152,030
Days per Year	For leap years, days = 366	t_{yr}	days/yr	365

Emission Summary			
Annual Throughput, gal	8,921,500	**Annual Emissions**	0.39
Annual Turnovers	7.84		
Month	**Emissions, lbs**	**Emissions, tons**	
Jan	26.60	0.013	
Feb	31.78	0.016	
Mar	48.79	0.024	
Apr	68.16	0.034	
May	91.95	0.046	
Jun	104.09	0.052	
Jul	114.72	0.057	
Aug	103.13	0.052	
Sep	80.61	0.040	
Oct	56.25	0.028	
Nov	37.23	0.019	
Dec	26.45	0.013	

Note: The emission summary table is pulled into the Tank Emissions tab using cell references A31:B42. The emission summary must remain at this cell reference to function properly.

Calculations				
Parameter Title	**Notes**	**Parameter Symbol**	**Units**	**Reference or Equation**
Service				
Type of Substance	Select Organic Liquid, Petroleum Distillate, or Crude			
Contents of Tank	Select from list (add new compounds in 'VOLs' tab):			= User specified
Speciation Profile	Select from list (add new in 'Speciation Input' tab):			= User specified
Speciation Profile Type				= User specified
Monthly Throughput		Q	gal/month	= User specified
Days-In-Service	Total days per month minus the days tank has a service change, is out of service, or for non-routine events.	t_{IS}	days	
Constant in the vapor pressure equation	Used in ΔP_V only for petroleum liquids. If full speciation profile specified, leave blank.	B	°R	= Not Applicable {Organic liquids and full speciation profiles}
Average Liquid Height	Leave blank if unknown. Not applicable for horizontal Tanks. Fill out for tanks operating on level control.	H_L	ft	= User specified if known = H_{LX} / 2 {default}
Liquid Bulk Temperature	Input data through either Tank List tab, or Tank Throughput tab.	$T_{B\text{-input}}$	°F	= specified by user
Vapor Space Outage		H_{VO}	ft	= $H_S - H_L + H_{RO}$ {all other fixed roof tanks, Eqn. 1-16} = (H_E / 2) {horizontal tanks only}
Daily Total Solar Insolation Factor		I	Btu / ft^2 day	
Vent Setting Correction Factor		K_B		When (P_{BP} > 0.03 psig) and (K_N (P_{BP} + P_A) / (P_I + P_A)) > 1.0 {Eqn. 1-40} = (((P_I + P_A) / K_N) - $P_{VA,Tla}$) / (P_{BP} + P_A - $P_{VA,Tla}$) {Eqn. 1-41} Otherwise = 1
Vapor Space Expansion Factor	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in the tool that tank location is known. True vapor pressure based on liquid stock. If KE < 0, no standing losses occur. Per AP 42, 1> K_E ≥ 0.	K_E		= (ΔT_V / (T_{LA} + 459.67 °R)) + ((ΔP_V - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}
Working Loss Turnover (Saturation) Factor	Per Eqn. 1-35, annual threshold for turnovers is 36. Equation modified to a monthly form by converting the monthly turnovers to a theoretical annual turnover equivalent.	K_N		= (180 + (N * t_{yr} / t_{IS})) / (6 * (N * t_{yr} / t_{IS})) {(N * t_{yr} / t_{IS}) > 36, Eqn. 1-35} = 1 {(N * t_{yr} / t_{IS}) ≤ 36, Eqn. 1-35}
Working Loss Product Factor		K_P		= 0.75 {crude oils, Eqn. 1-35} = 1 {all other organic liquids}
Vented Vapor Saturation Factor	Constant 0.053 has units of 1/(psia-ft). True vapor pressure based on liquid surface temperature.	K_S		= 1 / (1 + 0.053 * $P_{VA,Tla}$ * H_{VO}) {Eqn. 1-21}
Vapor Molecular Weight	When using full speciation profiles, calculated as the weighted average of the M_V of each component.	M_V	lb/lb-mole	= VOL data of tank contents {partial speciation} M_V = Σ (M_{Vi} * ($P_{VA,Tla\text{-}i}$/$P_{VA,Tla}$)) {full speciation, Eqn. 1-23}
Liquid Molecular Weight		M_L	lb/lb-mole	M_L = 1 / Σ (Z_{Li} / M_{Li}) {full speciation}
Number of Turnovers per Month	Constant 5.614 has units of ft^3/bbl.	N		= 5.614 * Q * (bbl / 42 gal) / V_{LX} (Eqn. 1-36} and {Eqn. 1-37}
Average Daily Minimum Ambient Temperature		T_{AN}	°F	
Average Daily Maximum Ambient Temperature		T_{AX}	°F	
Daily Average Ambient Temperature		T_{AA}	°F	= (T_{AX} + T_{AN}) / 2 {Eqn. 1-30}
Daily Minimum Liquid Surf. Temperature, F		T_{LN}	°F	= T_{LA} - 0.25 * ΔT_V {Fig. 7.1-17}
Daily Maximum Liquid Surf. Temperature, F		T_{LX}	°F	= T_{LA} + 0.25 * ΔT_V {Fig. 7.1-17}
Daily Vapor Temperature Range	Constant 0.028 has units of (°R-ft^2-day/Btu)	ΔT_V	°R	For fully insulated tanks = 0 For uninsulated tanks: If default Hs/D = 0.7 * (TAX - TAN) + 0.02 * αTot * I {Eqn. 1-7} If specific Hs/D = [1 – 0.8 / (2.2 Hs/D + 1.9)] (TAX – TAN) + [0.042 αRI + 0.026 (Hs/D) αSI] / (2.2 Hs/D + 1.9) {Eqn. 1-6} For partial insulated tanks: = 0.6 * (TAX - TAN) + 0.02 * αR * I {Eqn. 1-8}

Parameter Title	1	2	3	4	5	6	7	8	9	10	11	12
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Service	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**	**Main Service**
Type of Substance	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate	Petroleum Distillate
Contents of Tank	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2	Distillate fuel oil no. 2
Speciation Profile	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)	Distillate Fuel Oil No. 2 (Diesel)
Speciation Profile Type	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation	Partial Speciation
Monthly Throughput	743,458	743,458	743,458	743,458	743,458	743,458	743,458	743,458	743,458	743,458	743,458	743,458
Days-In-Service	31	28	31	30	31	30	31	31	30	31	30	31
Constant in the vapor pressure equation	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907	8,907
Average Liquid Height	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Outage	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Daily Total Solar Insolation Factor	823	1,079	1,409	1,773	1,936	1,936	1,936	1,718	1,491	1,211	949	753
Vent Setting Correction Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Vapor Space Expansion Factor	0.0519	0.0621	0.0741	0.0858	0.0877	0.0845	0.0838	0.0764	0.0701	0.0642	0.0576	0.0493
Working Loss Turnover (Saturation) Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Working Loss Product Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Vented Vapor Saturation Factor	0.995	0.994	0.992	0.990	0.986	0.984	0.982	0.983	0.986	0.990	0.993	0.995
Vapor Molecular Weight	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
Liquid Molecular Weight	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0	188.0
Number of Turnovers per Month	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Average Daily Minimum Ambient Temperature	38.00	40.40	46.60	53.50	62.90	70.10	73.20	72.70	67.30	56.20	45.90	39.10
Average Daily Maximum Ambient Temperature	57.40	61.20	68.70	76.00	83.40	88.50	91.30	90.40	85.50	76.40	67.20	58.40
Daily Average Ambient Temperature	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Minimum Liquid Surf. Temperature, F	44.79	47.68	54.34	61.38	70.08	76.54	79.54	78.90	73.67	63.27	53.36	45.86
Daily Maximum Liquid Surf. Temperature, F	58.02	63.63	73.65	84.08	93.65	99.48	102.39	99.67	92.55	80.23	68.29	58.42
Daily Vapor Temperature Range	26.45	31.90	38.62	45.41	47.15	45.89	45.71	41.54	37.76	33.92	29.86	25.13

Calculations

Parameter Title	Notes	Parameter Symbol	Units	Reference or Equation
Service				
Daily Average Liquid Surf. Temperature	Constant 0.0079 has units of (°R-ft^2-day/btu).	T_{LA}	°F	For fully insulated tanks = T_B For partial insulated tanks = 0.3 * T_{AA} + 0.7 * T_B + 0.005 * α_R * I {Eqn. 1-29} For uninsulated tanks = 0.4 * T_{AA} + 0.6 * T_B + 0.005 * α_{Tot} * I {Eqn. 1-28} for default Hs/D = (0.5 - 0.8/(4.4Hs/D + 3.8)) T_{AA} + (0.5 + 0.8/(4.4Hs/D+3.8)) * T_B + (0.021α_RI + 0.013(Hs/D)α_SI)/(4.4Hs/D+3.8) {Eqn. 1-27} for specific Hs/D
Liquid Bulk Temperature	If T_B is unknown, see AP-42 7.1 Eqn 1-27 Note 5.	T_B	°F	= specified by user {Insulated tanks only} = T_{AA} + 0.003 * α_{Tot} * I {Eqn. 1-31}
Daily Average Vapor Space Temperature	It is a new parameter in the new version of AP 42	T_V	°F	For fully insulated tanks = TB For partial insulated tanks = 0.6 * TAA + 0.4 * TB + 0.01 * αR * I {Eqn. 1-34} For uninsulated tanks If default Hs/D = 0.7 TAA + 0.3 TB + 0.009 α I {Eqn. 1-33} If specific Hs/D = [(2.2 Hs/D + 1.1) TAA + 0.8 TB + 0.021 αRI + 0.013 (Hs/D) αSI] / [2.2 Hs/D + 1.9] {Eqn. 1-32}
Vapor Pressure at Daily Av. Liquid Surf. Temp.	Used for speciated emissions and most vapor pressures. $P_{VA,Tla}$ uses T_{LA}.	$P_{VA,Tla}$	psia	*{full speciation profiles, Eqn. 1-24}:* Sum of partial true vapor pressures components. *{partial/no speciation profiles}: Calculated* vapor pressures at T (°F) with provided coefficients or interpolated with provided vapor pressures at different temperatures.
Vapor Pressure at Daily Min. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VN} uses T_{LN}.	P_{VN}	psia	
Vapor Pressure at Daily Max. Liquid Surf. Temp.	Used for ΔP_V. Per AP-42 7.1-13 Note 5, P_{VX} uses T_{LX}.	P_{VX}	psia	
Daily Vapor Pressure Range		ΔP_V	psia	= P_{VX} - P_{VN} {Eqn. 1-9}
Vapor Density		W_V	lb/ft^3	= (M_V * $P_{VA,Tla}$) / (R * (T_{LA} + 459.67 °R)) {Eqn. 1-21}
Vapor Space Volume		V_V	ft^3	= (π/4 * D_E^2) * H_{VO} {Eqn. 1-3}
Heating Cycle				
Heating Cycle Period (days)	How many days in one heating cy	$Days_H$	days	
Max Liquid Bulk Temperature	Highest liquid temperature in one heating cycle.	T_{BX}	°F	
Min Liquid Bulk Temperature	Lowest liquid temperature in one heating cycle.	T_{BN}	°F	
Average Liquid Bulk Temperature	Average liquid temperature in one heating cycle.	T_{BA}	°F	
Vapor Temperature Range		ΔT_{V-H}	°R	= T_{BX} - T_{BN} {Eqn. 8-1}
Vapor Pressure Range		ΔP_{V-H}	psi	=P_{VX} - P_{VN} = P_{BX} - P_{BN} {Eqn. 1-9}
Vapor Space Expansion Factor from Heating Cycle	Per AP-42 7.1-12, you can use Eqn. 1-12 in lieu of Equation 1-5, if PVA,Tb < 0.1 psia. But it is not used in this tool. It is required in	K_{E-H}		= (ΔT_{V-H} / (T_{LA} + 459.67 °R)) + ((ΔP_{V-H} - ΔP_B) / (P_A - $P_{VA,Tla}$)) ≥ 0 { Eqn. 1-5}
Standing Storage Loss	Uncontrolled emissions. No standing or breathing losses occur for underground tanks per AP-42 Eqn. 7.1-15.	L_S	lbs/month	= 0 {underground tanks only} = t_{IS} * V_V * W_V * K_E * K_S {Eqn. 1-2}
Standing Storage Loss from Heating Cycles	Uncontrolled emissions. Standing losses occur when there is heating cycle for fully insulated tanks, Per AP-42 Section 7.1.3.8.4	L_{S-H}	lbs/month	= 0 {no heating cycle} = t_{IS-H} * V_V * W_V * K_{E-H} * K_S {Eqn. 1-2}
Working Loss	Uncontrolled emissions. True vapor pressure based on liquid surface.	L_W	lbs/month	= Q * (5.614 ft^3/bbl) * (bbl / 42 gal) * W_V * K_N * K_P * K_B {Eqn. 1-35}
Total Losses	**Uncontrolled emissions.**	**L_T**	**lbs/month**	**= (L_S + L_W) {Eqn. 1-1}**

Parameter Title	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service	Main Service
Daily Average Liquid Surf. Temperature	51.40	55.66	63.99	72.73	81.86	88.01	90.96	89.28	83.11	71.75	60.82	52.14
Liquid Bulk Temperature	47.70	50.80	57.65	64.75	73.15	79.30	82.25	81.55	76.40	66.30	56.55	48.75
Daily Average Vapor Space Temperature	55.11	60.51	70.33	80.71	90.57	96.72	99.67	97.01	89.82	77.20	65.09	55.53
Vapor Pressure at Daily Av. Liquid Surf. Temp.	0.0049	0.0056	0.0074	0.0098	0.0129	0.0156	0.0170	0.0162	0.0134	0.0095	0.0067	0.0050
Vapor Pressure at Daily Min. Liquid Surf. Temp.	0.0039	0.0043	0.0054	0.0068	0.0090	0.0110	0.0121	0.0118	0.0101	0.0072	0.0052	0.0040
Vapor Pressure at Daily Max. Liquid Surf. Temp.	0.0061	0.0073	0.0101	0.0138	0.0184	0.0217	0.0236	0.0219	0.0178	0.0123	0.0085	0.0062
Daily Vapor Pressure Range	0.002	0.003	0.005	0.007	0.009	0.011	0.012	0.010	0.008	0.005	0.003	0.002
Vapor Density	0.0001143	0.0001306	0.0001688	0.0002189	0.0002851	0.0003391	0.0003680	0.0003519	0.0002965	0.0002137	0.0001537	0.0001171
Vapor Space Volume	83,220	83,220	83,220	83,220	83,220	83,220	83,220	83,220	83,220	83,220	83,220	83,220
Heating Cycle												
Heating Cycle Period (days)	--	--	--	--	--	--	--	--	--	--	--	--
Max Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Min Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Average Liquid Bulk Temperature	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Temperature Range	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Pressure Range	--	--	--	--	--	--	--	--	--	--	--	--
Vapor Space Expansion Factor from Heating Cycle	--	--	--	--	--	--	--	--	--	--	--	--
Standing Storage Loss	15.2335	18.7966	32.0113	46.4010	63.6244	70.3878	78.1474	68.1551	51.1462	35.0189	21.9514	14.8058
Standing Storage Loss from Heating Cycles	--	--	--	--	--	--	--	--	--	--	--	--
Working Loss	11.36	12.98	16.78	21.75	28.33	33.70	36.57	34.97	29.46	21.23	15.28	11.64
Total Losses	**26.60**	**31.78**	**48.79**	**68.16**	**91.95**	**104.09**	**114.72**	**103.13**	**80.61**	**56.25**	**37.23**	**26.45**

Speciated Component Emissions	Species ID	Controlled with Carbon Adsorpti	Annual Emissions	Controlled Monthly Emissions ($L_{T,CD-i}$ lb/month) $= (P_{VA,Tla-i} * M_{V-i} / (P_{VA,Tla} * M_V) * (1 - CD_{eff})) * L_T$											
Component Name			lb/yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hexane (n-)	1	--	0.30	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.03	0.02	0.02	0.01
Benzene	2	--	1.50	0.06	0.07	0.10	0.13	0.17	0.19	0.20	0.18	0.15	0.11	0.08	0.06
Trimethylpentane (2,3,4)	3	--	0.00												
Toluene	4	--	17.95	0.64	0.76	1.14	1.57	2.08	2.32	2.54	2.29	1.81	1.30	0.88	0.63
Ethylbenzene	5	--	2.44	0.08	0.09	0.15	0.21	0.29	0.33	0.36	0.32	0.25	0.17	0.11	0.08
Xylene (m-)	6	--	47.61	1.52	1.84	2.88	4.08	5.58	6.37	7.04	6.32	4.90	3.36	2.18	1.52
Isopropyl benzene {cumene}	7	--	0.00												
MTBE {Methyl tert-butyl ether}	8	--	0.00												
Trimethylbenzene (1,2,4)	9	--	40.48	1.14	1.40	2.29	3.38	4.82	5.64	6.31	5.63	4.25	2.77	1.71	1.14
Cyclohexane	10	--	0.00												
Gasoline (RVP 13)	11	--	0.00												
Ethanol {ethyl alcohol}	12	--	0.00												
Acetaldehyde	13	--	0.00												
Heptane (n-)	14	--	0.00												
Isopentane {2-methylbutane}	15	--	0.00												
Pentane (n-)	16	--	0.00												
Butane	17	--	0.00												
Naphthalene	18	--	0.39	0.01	0.01	0.02	0.03	0.05	0.06	0.06	0.06	0.04	0.03	0.02	0.01
Benzo(g,h,i)perylene	19	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PACs (Chrysene)	20	--	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
--	21	--													

Table C-37. Sitewide Potential Emissions

Pollutant	Annual Emissions (tpy)
SO_2	41.05
NO_X	957.97
CO	474.35
Total PM	233.78
Filterable PM	70.54
Condensable PM	163.23
Total PM_{10}	233.78
Total $PM_{2.5}$	233.78
VOC	90.15
Lead	2.60E-02
Sulfuric Acid Mist (H_2SO_4)	4.10
GHGs (CO_2e)	1,760,859
Total HAP	8.77
Max Single HAP[1]	2.01

1. Max Single HAP is Formaldehyde.

APPENDIX D. CONTROL COST ANALYSES

Table D-1. Potential Emissions for Modified Combustion Turbine Systems (T1 - T4)[1]

Pollutant Emissions	Maximum Annual Emissions for each Turbine (tpy)
Total NO_X Emissions (per turbine)	156.8
Total CO Emissions (per turbine)	97.1
Total VOC Emissions (per turbine)	12.6
Total CO_2 Emissions (per turbine)	312,813

1. Emissions taken from Tables C-11, identical for each of the 4 modifed turbines (T1 - T4).

Table D-2. Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Capital Cost (Each Turbine)

Capital Cost Summary			Cost
TOTAL CAPITAL INVESTMENT CORRELATION - OIL FIRING[1]			
Q_B - Maximum Heat Input (MMBtu/hr, oil firing)		1,365	
ELEVF - Elevation Factor[2]		N/A	
RF - Retrofit Factor[3]		1.0	
TOTAL CAPITAL INVESTMENT - OIL FIRING[4]	$TCI = 7{,}850 \times \left(\frac{2{,}200}{Q_B}\right)^{0.35} \times Q_B \times ELEVF \times RF$	**TCI =**	**$17,137,916**
TOTAL CAPITAL INVESTMENT CORRELATION - GAS FIRING[1]			
Q_B - Maximum Heat Input (MMBtu/hr, gas firing)		1,180	
ELEVF - Elevation Factor[2]		N/A	
RF - Retrofit Factor[3]		1.0	
TOTAL CAPITAL INVESTMENT - GAS FIRING[4]	$TCI = 10{,}530 \times \left(\frac{1{,}640}{Q_B}\right)^{0.35} \times Q_B \times ELEVF \times RF$	**TCI =**	**$18,869,101**
TOTAL CAPITAL INVESTMENT[5]		**TCI =**	**$18,869,101**

1. In the absence of site-specific quotes on SCR costs, the most relevant cost correlations were used from U.S. EPA CCM, Section 4, Chapter 2, "Selective Catalytic Reduction," Seventh Edition, June 2019. Equation 2.52 for industrial, oil-fired units (≥275 to ≤5,500 MMBtu/hr) was used to calculate TCI for oil firing. Equation 2.53 for industrial, gas-fired units (≥205 to ≤4,100 MMBtu/hr) was used to calculate TCI for gas firing.
2. Consistent with the note in Subsection 2.4.1.4 and to be conservative, increases in costs related to elevation factor adjustments are not included.
3. Retrofit factor of 1.0 for retrofits of average difficulty.
4. The purchased equipment cost was corrected for inflation to May 2023 dollars via PPI industry group data for total manufacturing industries.
5. Maximum of calculated TCI for oil firing and gas firing.

Table D-3. Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Annual Cost (Each Turbine)

Annual Cost Summary					**Annual Cost**
DIRECT ANNUAL COSTS					
OPERATION AND MAINTENANCE[1]					
Maintenance (0.5% of TCI)					$94,346
REAGENT[2]					
	NO_{Xin} - Inlet NO_X (lb/MMBtu, gas firing)			4.49E-02	
	Q_B - Maximum Heat Input (MMBtu/hr, gas firing)			1,180	
	η_{NOx} - NO_X Removal Efficiency of the SCR[3]			0.80	
	SRF - Stoichiometric Ratio Factor for Ammonia			1.05	
	$M_{reagent}$ - Molecular Weight of Ammonia (lb/mol)			17.03	
	M_{NOx} - Molecular Weight of NO_2 (lb/mol)			46.01	
	Ammonia Requirement (lb/hr) $\dot{m}_{reagent} = \frac{NO_{x_{in}} \times Q_B \times \eta_{NOx} \times SRF \times M_{reagent}}{M_{NO_x}}$			16.46	
Ammonia Cost[4]	16.46 lb/hr at	$334.30	per ton		$11,554
CATALYST					
Catalyst Replacement[5]					$2,105,225
Catalyst Life (years)					3.00
Annual Interest Rate (%)					7.00%
Future Worth Factor					0.311
Total Annual Catalyst Replacement Cost					$654,834
UTILITIES[6]					
	Q_B - Maximum Heat Input (MMBtu/hr, gas firing)			1,180	
	CoalF - N/A			1	
	HRF - Default Heat Rate Factor			10	
	Electricity Requirement (kW) $P = (0.1 \times Q_B) \times (1{,}000) \times (0.0056) \times (CoalF \times HRF)^{0.43}$			1,779	
Electricity Cost[7]	1,779 kW at	$0.0615	per kW-hr		$459,404
TOTAL DIRECT ANNUAL COSTS (DAC)				**DAC =**	**$1,220,137**
INDIRECT OPERATING COSTS[8]					
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)[9]					
	30 years @ 8.25% interest	CRF =	0.0909		$1,715,785
TOTAL INDIRECT ANNUAL COSTS (IAC)				**IAC =**	**$1,715,785**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)				**TAC=**	**$2,935,922**
Cost Effectiveness Summary					
Annual Control Cost ($)					**$2,935,922**
Pollutant to be Removed [NO_X] (tpy)[3]					**125.46**
CONTROL COST EFFECTIVENESS ($/ton)					**$23,402**

1. U.S. EPA CCM, Section 4, Chapter 2, "Selective Catalytic Reduction," Seventh Edition, June 2019.
2. Reagent usage calculated from Equation 2.35 in Subsection 2.3.13. Conservatively calculated for gas firing case; oil firing would require more reagent.
3. Flue gas temperature for gas firing is estimated to be 1,006°F. Per Subsection 2.2.2, as the temperature increases above 750°F, the reaction rate and resulting NO_X removal efficiency begin to decrease. Conservatively using 80% as NO_X removal efficiency based on upper bound for temperature from Figure 2.2.
4. Reagent cost from S&P Global Commodity Insights data for Gray Ammonia in May 2023. Converted to $/ton. Maximum of 4,200 hr/yr of operation.
5. Catalyst replacement cost 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 May 2023 dollars via PPI industry group data for total manufacturing industries.
6. Electricity usage calculated from Equation 2.61 in Subsection 2.4.2. Conservatively calculated for gas firing case; oil firing would require more power.
7. Electricity cost for industrial users from U.S. EIA State Profile for Georgia. Maximum of 4,200 hr/yr of operation.
8. Administrative charges conservatively assumed to be $0.
9. Average equipment life of 30 years per Subsection 2.4.2 and Bank Prime Rate of 8.25% used based on U.S. Federal Reserve data.

Table D-4. Oxidation Catalyst Economic Feasibility Assessment For Capital Cost (Each Turbine)

Capital Cost Summary		Capital Cost
DIRECT COSTS[1]		
TOTAL PURCHASED EQUIPMENT COST (PEC)	**PEC =**	**$3,513,245**
(1) Purchased Equipment		
(a) Total Equipment[2]		**$2,977,327**
(b) Instrumentation (0.1 x [1a])		**$297,733**
(c) Sales taxes (0.03 x [1a])		**$89,320**
(d) Freight (0.05x [1a])		**$148,866**
TOTAL DIRECT INSTALLATION COST, DC	**DC =**	**$1,053,974**
(2) Direct Installation		
(a) Foundation (0.08 x PEC)		**$281,060**
(a) Handling (0.14 x PEC)		**$491,854**
(c) Electrical (0.04 x PEC)		**$140,530**
(d) Piping (0.02 x PEC)		**$70,265**
(e) Insulation (0.01 x PEC)		**$35,132**
(f) Painting (0.01 x PEC)		**$35,132**
TOTAL DIRECT COST (TDC)	**TDC =**	**$4,567,219**
INDIRECT COSTS[1]		
(3) Engineering (0.1 x PEC)		$351,325
(4) Construction (0.05 x PEC)		$175,662
(5) Contractor fees (0.1 x PEC)		$351,325
(6) Start-up (0.02 x PEC)		$70,265
(7) Performance test (0.01 x PEC)		$35,132
TOTAL INDIRECT COST (TIC)	**TIC =**	**$983,709**
PROJECT CONTINGENCY ((TDC + TIC)*0.1))[3]	**PC =**	**$555,093**
TOTAL CAPITAL INVESTMENT (TCI = TDC + TIC + PC)[4]	**TCI =**	**$6,106,020**

1. General costing approach from U.S. EPA CCM, Section 3.2, Chapter 2, "Incinerators and Oxidizers," Seventh Edition, November 2017.

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. The purchased equipment cost was corrected for inflation to May 2023 dollars via PPI industry group data for total manufacturing industries.

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 For Annual Cost (Each Turbine)

Annualized Cost		Annual Cost
TOTAL CAPITAL INVESTMENT, TCI	**TCI =**	**$6,106,020**
DIRECT ANNUAL COSTS[1]		
ANNUAL LABOR COST (1a + 1b)		**$12,910**
(1) Operating Labor		
(a) Operating Cost		$11,230
(b) Supervisor (0.15 x 1a)		$1,680
MAINTENANCE (2a +2b)		**$15,400**
(2) Maintenance		
(a) Labor		$7,700
(b) Material (100% of 1a)		$7,700
CATALYST REPLACEMENT[2]		**$969,499**
(3) Catalyst Replacement		$969,499
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$997,809**
INDIRECT ANNUAL COSTS		
(4) Overhead (0.6 x (Annual Labor + Maintenance)		$16,986
(5) Administrative charges (0.02 x TCI)		$122,120
(6) Property Tax (0.01 x TCI)		$61,060
(7) Insurance (0.01 x TCI)		$61,060
(8) Capital Recovery (CRF x (TCI - 1.08*Annual Catalyst Cost))[3]		$524,889
20 years @ 8.25% interest CRF = 0.1038		
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$786,116**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)[4]	**TAC=**	**$1,783,925**
Cost Effectiveness Summary		
POLLUTANT TO BE REMOVED (CO) (tpy)[5]		**77.66**
POLLUTANT TO BE REMOVED (VOC) (tpy)[5]		**10.07**
COST EFFECTIVENESS ($/ton CO removed)		**$22,970**
COST EFFECTIVENESS ($/ton VOC removed)		**$177,109**

1. Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States, stats last updated May 2022. Hourly rates for operators based on data for Power Plant Operators (51-8013). Hourly rates for maintenance based on data for Industrial Machinery Mechanics (49-9041). https://www.bls.gov/oes/current/oes_nat.htm.
Operating Labor Cost = 4,200 hours of Operation/Labor = 0.5 hours/shift × Labor Rate ($42.77/hr) × (Operating Hours/8 hours/shift)
Maintenance Labor Cost = 4,200 hours of Operation/Labor = 0.5 hours/shift × Labor Rate ($29.32/hr) × (Operating Hours/8 hours/shift)

2. Based on 2003 EPA Economic Analysis (Conservatively no PPI or cost ratios used).
https://www.epa.gov/sites/production/files/2020-07/documents/combustion-turbines_eia_neshap_final_08-2003.pdf

3. 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 20-year equipment life (per Table 2.12) and a 8.25% interest rate (Bank Prime Rate based on U.S. Federal Reserve data), CRF = 0.1038.

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 Annualized 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**
Per Turbine:[1]	
Annual CO_2 Captured (tpy)	281,532
Gross Power Output (Natural Gas) (kW)	105,340
Gross Power Output (Fuel Oil) (kW)	118,267
Nominal Power Output Before Project (MW)	108
CO_2 Captured (kg/yr)[2]	255,401,916
Proposed Project Increase in Power Output (MW)[3]	13
Energy Used for Capture (kWh/kg CO_2 processed)[4]	0.354
Energy Used for Capture (kWh/yr)[5]	90,412,278
Energy Used for Capture (MWh/yr)	90,412
Power Output After Project (without CCS)(MW)	121
Power Used for Capture if CCS included (MW)[6]	21.5
Power Output After Project (with CCS)(MW)	99.7

1. Captured amount calculated in Table D-7, Gross Power Output per Siemens data, Nominal Power Output per Title V permit, and each value is identical for the 4 turbines.

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 Fuel Oil to Natural Gas Gross Power Output, which is then applied to the nominal power output (MW) to estimate project increases. kW = MW * 1,000 kW/MW. Theoretical estimate based on (gross power output fuel oil / gross power output natural gas).

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) / [Hours for natural gas combustion + Hours for fuel oil combustion, per in Table D-7] (hr/yr).

Table D-7. Assumptions Used in CCS Cost Estimation for Turbines[1]

Parameters	**Value**	**Unit**
Pipeline Length[2]	232	mi
Pipeline Diameter[3,4,5]	17	in
Average Storage Site Depth[6]	3,000	m
	9,843	ft
Number of Injection Wells[7]	1	
Per Turbine:[8]		
Turbine Operating Hours (Natural Gas)	3750	hr/yr
Turbine Operating Hours (Fuel Oil)	450	hr/yr
Uncontrolled Annual Natural Gas CO_2 Emissions	262,971	tpy
Uncontrolled Maximum Natural Gas Daily CO_2 Emissions	1,683	tpd
Uncontrolled Annual Fuel Oil CO_2 Emissions	49,842	tpy
Uncontrolled Maximum Daily Fuel Oil CO_2 Emissions	2,658	tpd
Control Efficiency[9]	90%	
Annual Captured CO_2 Emissions	281,532	tpy
Daily Maximum Captured CO_2 Emissions	2,392	tpd
Post-Project Net Power Output without CCS	121	MW
Post-Project Net Power Output with CCS[10]	100	MW
All Turbines:	4	turbines
Annual Captured CO_2 Emissions	1,126,128	tpy
Daily Maximum Captured CO_2 Emissions	9,570	tpd
Post-Project Net Power Output without CCS	485	MW
Post-Project Net Power Output with CCS	399	MW

1. For all cost analysis calculations, the report utilized resources for Combined Cycle Combustion Turbines (CCCTs) for Natural 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 (Paluxy Formation, Citronelle, Alabama) per the Southeast Regional Carbon Sequestration Partnership (SECARB), conservatively assuming the shortest distance as the pipeline route. Note that the Black Warrior Basin that was a part of SECARB's Phase I study, has reverted back to its original use for coalbed methane production. https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.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 232 mile long pipeline is 17 inches at 10,000 tons/day CO_2.

4. The required diameter is conservatively estimated by scaling 17 inches of diameter (necessary for a 10,000 tons/day CO_2 flowrate) by the square root of the ratio of the flowrates (for all turbines).
17 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 232 mile long pipeline is 17 inches at 9,570 tons/day CO_2. Since a 17 inch pipeline would not be available for installation, a 16 inch size was selected.

6. The injection zone for the Citronelle Project is the upper Paluxy Formation, which occurs at a depth of 3,000 to 3,400 meters. Shallowest depth is used for conservatism. https://netl.doe.gov/coal/carbon-storage/atlas/secarb/phase-III/citronelle-projects

7. Conservatively assumes only 1 injection well is needed.

8. Heat Inputs, Operating Hours, and Emissions taken from Tables C-8 and C-9, identical for each of the 4 turbines.

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); taken from Table D-6

Table D-8. Capital and O&M Costs of Carbon Capture

		December 2018 Dollars	May 2023 Dollars[2]
Capture Capital Costs for CCCTs [1,2,3]		$ 294,246,133	$ 371,080,250
	Total Capital	$ 294,246,133	$ 371,080,250
O&M			
Fixed Operating Costs[2,4]	Labor, Property Taxes, Insurance	$ 8,987,098	$ 11,333,826.89
Variable Operating Costs[2,5]	Water, Chemicals (MEA Solvent)	$ 3,293,938	$ 4,154,058
	Total O&M	$ 12,281,037	$ 15,487,885

1. Based on the October 2022 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 577) and Exhibit 5-31, Case B31B Total Plant Cost Details (page 595). Cost results are reported in 2018 dollars.

Capture Capital Costs = [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 (kW)]

Total Plant Capital Cost - No Capture	780	$/kW
Total Plant Capital Cost - With Capture	1686	$/kW

2. The purchased equipment cost was corrected for inflation to May 2023 dollars via PPI industry group data for total manufacturing industries.

PPI for December 2018	195.2
PPI for May 2023	246.171

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. OPC conservatively estimated there is no additional cost for connecting the turbines into a single pipeline for purposes of this estimate.
4. Based on the October 2022 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 579) and Exhibit 5-33. Case B31B Initial and Annual Operating and Maintenance Costs (page 597).

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	26.794	$/kW
Total Fixed Operating Costs - With Capture	55.107	$/kW

5. Based on the October 2022 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 579) and Exhibit 5-33. Case B31B Initial and Annual Operating and Maintenance Costs (page 597). 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 is the sum of hours/yr for Natural Gas and hours/yr for Fuel Oil.

Variable Operating Costs = [Total Variable Operating Cost (capture) ($/kWh) * Post-Project Net Power Output with CCS (kW)] - [Total Variable Operating Cost (no capture) ($/kWh) * Post-Project Net Power Output without CCS (kW)] * Turbine operating hours/year

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	$/kWh
Maintenance Materials	*2.58E-03*	*$/kWh*
Water Cost	*3.95E-04*	*$/kWh*
Makeup and Waste Water Treatment Chemicals	*3.40E-04*	*$/kWh*
CO_2 Capture System Chemicals	*4.10E-04*	*$/kWh*
Triethylene Glycol Consumption	*1.94E-04*	*$/kWh*
Triethylene Glycol Waste Disposal	*9.99E-06*	*$/kWh*
Thermal Reclaimer Unit Waste	*4.30E-06*	*$/kWh*
Total Variable Operating Costs - With Capture	3.93E-03	$/kWh

Table D-9. Capital and O&M Costs of Pipeline Transportation

Capital Costs	Factor	Unit	December 2011 Dollars	December 2018 Dollars	May 2023 Dollars[3]
Pipeline Costs[1]					
Pipeline Cost	$ 1,250,000	$/mi for a 16 inch pipeline	--	$ 290,000,000	$ 365,725,359
		Total Capital	--	$ 290,000,000	$ 365,725,359
O&M[2]					
Fixed O&M	$ 8,454	$/mile/yr	$ 1,961,328	--	$ 2,546,530

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 16 inch pipeline using the Parker model. The pipeline cost was available for a 16 inch or a 20 inch pipeline diameter. Although Table D-3 above calculates the necessary pipeline diameter as 17 inches for maximum daily operations, a 16 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 May 2023 dollars via PPI industry group data for total manufacturing industries.

PPI for December 2011	189.6
PPI for December 2018	195.2
PPI for May 2023	246.171

Table D-10. Capital and O&M Costs of Geological Storage

Capital Costs[1]	**Factor**	**Unit**	**June 2007 Dollars**	**May 2023 Dollars[2]**
Site Screening and Evaluation		$	$ 4,738,488	$ 7,125,707.57
Injection Wells	$240{,}714 * e^{0.0008*\text{well-depth}}$	$/injection well, well-depth(m)	$ 2,653,433	$ 3,990,215
Injection Equipment	$94{,}029 * (7{,}389 / (280 * \#\text{ of injection wells}))^{0.5}$	$/injection well	$ 483,032	$ 726,380
Liability Bond		$	$ 5,000,000	$ 7,518,968
		Total Capital	$ 12,874,953	$ 19,361,270
O&M[1]				
Pore Space Acquisition	0.334	$/short tons CO_2 captured	$ 376,127	$ 565,617
Normal Daily Expenses	11,566	$/injection well	$ 11,566	$ 17,393
Consumables	2,995	$/yr/short tons CO_2/day	$ 28,661,144	$ 43,100,442
Surface Maintenance	$23{,}478 * (7{,}389 / (280 * \#\text{ of injection wells}))^{0.5}$	$/injection well	$ 120,608	$ 181,369
Subsurface Maintenance	7.08	$/ft depth/injection well	$ 69,685	$ 104,792
		Total O&M	$ 29,239,129	$ 43,969,613

1. "Estimating Carbon Dioxide Transport and Storage Costs," National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

2. Costs were adjusted from June 2007 dollars to May 2023 dollars via PPI industry group data for total manufacturing industries.

PPI for June 2007	163.7
PPI for May 2023	246.171

Table D-11. Overall Cost of CCS and Cost Effectiveness

			May 2023 Dollars
Total Capital Investment (TCI)[1]			$ 756,166,879
Capital Recovery Factor (CRF)[2]		0.1507	
Interest	8.25%		
Lifespan (years)	10		
Amortized Cost	CRF*TCI		$ 113,965,158
Total O&M Cost			$ 62,004,028
Total Annualized Cost	Amortized Cost + O&M Costs		$ 175,969,186
Cost Effectiveness ($/ton)[3]			$ 156

1. Total Capital Investment (TCI) is equal to the sum of capital costs for carbon capture, transportation, and storage.

2. The capital recovery factor, CRF, is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate) calculated using the formula from the EPA OAQPS Control Cost Manual. Assuming a 10 year lifespan and a 8.25% interest rate (Bank Prime Rate based on U.S. Federal Reserve data).

3. Cost Effectiveness = Total Annualized Cost ($)/ CO_2 Emissions Captured (tons).

APPENDIX E. RBLC SEARCH RESULTS

Table E-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
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

Table E-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
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
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/psdtv/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% 02	24-HR BLOCK AVG, BY CEMS (NAT GAS)

Table E-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
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
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.

Table E-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
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
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	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

Table E-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
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	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	
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 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	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 E-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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLLING AVG EXCEPT <75% PEAK LOAD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	PPM	PPMVD AT 15%O2; 24-HR ROLL AVG EXC SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	PPM	@15%OX; 24-HR ROLL AVG EXCEPT START/SHUT
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLLING AVG EXCEPT <75% PEAK LOAD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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 for each CTG/HRSG unit.	3	PPM	PPMVD AT 15%O2; 24-HR ROLL AVG EXC SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	3	PPM	@15%OX; 24-HR ROLL AVG EXCEPT START/SHUT
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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-natural gas fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK

Table E-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
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--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 for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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-natural gas fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--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 for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Nitrogen Oxides (NOx)	Dry low NOx burners and selective catalytic reduction for NOx control for each CTG/HRSG unit.	60	LB/H	HOURLY; INCL STRT/SHUT IN COMBINED CYCLE

Table E-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
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	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

Table E-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
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.	Nitrogen Oxides (NOx)	DLN, WATER INJECTION	42.00	PPMVD @ 15% O2	3-HR ROLLING AVERAGE

Table E-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
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

Table E-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, 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		
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).	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

Table E-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, 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	
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

Table E-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
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		
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		

Table E-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
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
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	

Table E-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
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	
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	

Table E-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
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	
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 (°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
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

Table E-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 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
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

Table E-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
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	
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	

Table E-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
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
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

Table E-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 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	
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	

Table E-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
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
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

Table E-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.	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
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
TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	8/31/2022	Electric Generation Facility		Ten Simple Cycle NG Turbines	15.110	Natural Gas	465.8	MMBtu/hr	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Particulate matter, total (TPM)	good combustion design and operating practices and the use of low sulfur fuel	3.65	LB/HR	

Table E-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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 2.5 Âµ (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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 10 Âµ (TPM10)	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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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; APPLIES DURING ALL OPER. MODES
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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; APPLIES DURING ALL OPERAT. MODES
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL MODES
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 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, APPLY DURING ALL OPERATING MODES

Table E-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
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.210	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.210	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.210	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.110	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.110	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.110	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.110	Natural gas	0			Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and clean natural gas	0		

Table E-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
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.110	Natural gas	0			Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and clean natural gas	0		
COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	COLBERT	AL	9/21/2021	Electric Generating Facility		Three 229 MW Simple Cycle Combustion Turbines	15.110	Natural Gas	229	MW		Particulate matter, total < 10 Âµ (TPM10)		0.008	LB/MMBTU	3 HOUR AVG
COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	COLBERT	AL	9/21/2021	Electric Generating Facility		Three 229 MW Simple Cycle Combustion Turbines	15.110	Natural Gas	229	MW		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.008	LB/MMBTU	3 HOUR AVG
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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-natural gas fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 2.5 Âµ (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	1/7/2021	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-natural gas fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 10 Âµ (TPM10)	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	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1--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; APPLIES DURING ALL OPERAT. MODES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1--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; APPLIES DURING ALL OPERAT. MODES

Table E-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	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL OPERAT. MODES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL OPERAT. MODES
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.210	Natural Gas	3509	MMBtu/hr		Particulate matter, total (TPM)		0.0072	LB	MMBTU
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.210	Natural Gas	3509	MMBtu/hr		Particulate matter, total < 10 Âµ (TPM10)		0.0072	LB	MMBTU

Table E-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
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.210	Natural Gas	3509	MMBtu/hr		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.0072	LB	MMBTU
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.210	NATURAL GAS	0			Particulate matter, filterable (FPM)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.210	NATURAL GAS	0			Particulate matter, filterable < 10 Âµ (FPM10)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.210	NATURAL GAS	0			Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.110	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable (FPM)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.110	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable < 10 Âµ (FPM10)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.110	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur natural gas fuel	0		
AFE, INC. â€"LCM PLANT	AFE, INC	RACINE	WI	4/24/2018	a liquid crystal module (LCM) assembly plant		P90 â€" Natural Gas-Fired Emergency Generator	16.110	Natural Gas	9.51	mmBTU/hr	750 kW or 1,114 brake horsepower	Particulate matter, total (TPM)	The Use of Pipeline Quality Natural Gas and Good Combustion Practices	0		

Table E-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
TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	8/31/2022	Electric Generation Facility		Ten Simple Cycle NG Turbines	15.11	Natural Gas	465.8	MMBtu/hr	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Particulate matter, total (TPM)	good combustion design and operating practices and the use of low sulfur fuel	3.65	LB/HR	
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 2.5 Âµ (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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 10 Âµ (TPM10)	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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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; APPLIES DURING ALL OPER. MODES
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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; APPLIES DURING ALL OPERAT. MODES

Table E-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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL MODES
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 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, APPLY DURING ALL OPERATING MODES
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.21	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.21	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.21	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.11	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS

Table E-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
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.11	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.11	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.11	Natural gas	0			Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and clean natural gas	0		
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.11	Natural gas	0			Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and clean natural gas	0		
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.11	NATURAL GAS	0			Particulate matter, filterable (FPM)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU	
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.11	NATURAL GAS	0			Particulate matter, filterable < 10 Âµ (FPM10)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU	
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.11	NATURAL GAS	0			Particulate matter, filterable < 2.5 Âµ (FPM2.5)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU	
COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	COLBERT	AL	9/21/2021	Electric Generating Facility		Three 229 MW Simple Cycle Combustion Turbines	15.11	Natural Gas	229	MW		Particulate matter, total < 10 Âµ (TPM10)		0.008	LB/MMBTU	3 HOUR AVG
COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	COLBERT	AL	9/21/2021	Electric Generating Facility		Three 229 MW Simple Cycle Combustion Turbines	15.11	Natural Gas	229	MW		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.008	LB/MMBTU	3 HOUR AVG

Table E-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	1/7/2021	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-natural gas fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 2.5 Âµ (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	1/7/2021	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-natural gas fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Particulate matter, total < 10 Âµ (TPM10)	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	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--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; APPLIES DURING ALL OPERAT. MODES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--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; APPLIES DURING ALL OPERAT. MODES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL OPERAT. MODES
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 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; APPLIES DURING ALL OPERAT. MODES

Table E-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
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.21	Natural Gas	3509	MMBtu/hr		Particulate matter, total (TPM)		0.0072	LB	MMBTU
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.21	Natural Gas	3509	MMBtu/hr		Particulate matter, total < 10 Âµ (TPM10)		0.0072	LB	MMBTU
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.21	Natural Gas	3509	MMBtu/hr		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.0072	LB	MMBTU
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.21	NATURAL GAS	0			Particulate matter, filterable (FPM)	Low sulfur natural gas fuel	0		

Table E-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
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.21	NATURAL GAS	0			Particulate matter, filterable < 10 Âµ (FPM10)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.21	NATURAL GAS	0			Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.11	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable (FPM)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.11	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable < 10 Âµ (FPM10)	Low sulfur natural gas fuel	0		
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.11	NATURAL GAS	14552539	MMBTU/YR		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Low sulfur natural gas fuel	0		

Table E-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
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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.	EUEMGD		17.11		Diesel						Good combustion practices, burn ultra-low diesel fuel, and will be NSPS compliant.
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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.	EUEMGD		17.11		Diesel						Good combustion practices, burn ultra-low diesel fuel, and be NSPS compliant.
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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.	EUEMGD		17.11		Diesel						Ultra-low sulfur diesel fuel

Table E-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
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
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	Allison Weinstock
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
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
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
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	From
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
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
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
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.
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.
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

Table E-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
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
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
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
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
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
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	
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	
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
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
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

Table E-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
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.	Carbon Monoxide	Add-on control is CO Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	5.00	PPMVD@15%O 2	3 H ROLLING AV BASED ON ONE H BLOCK AV
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
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
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
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
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
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 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	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
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
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

Table E-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
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.	Aeroderivative Simple Cycle Combustion Turbine	16.110	Natural Gas	263	MM BTU/h		Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	36.00	PPMV	30 DAY ROLLING 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		Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	25.00	PPMV	30 DAY ROLLING AVERAGE
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
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
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
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
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) Cogeneration Gas-Fired Turbines (Treated Gas Compressor Turbines)	15.210	Natural Gas	576	MMBtu/hr	576 MMBtu/hr includes turbine and supplemental duct burner for waste heat recovery unit for cogeneration. EUs 1-6, Treat Gas Compressor Turbines.	Carbon Monoxide	Oxidation catalyst and good combustion practices	5.00	PPMV @ 15% O2	3-HOUR AVERAGE

Table E-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
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) Cogeneration Gas-Fired Turbines (CO2 Compressor Turbines))	15.210	Natural Gas	431	MMBtu/hr	431 MMBtu/hr includes turbine and supplemental duct burner for waste heat recovery unit for cogeneration. EUs 7-12, CO2 Compressor Turbines.	Carbon Monoxide	Oxidation catalyst and good combustion control practices	5.00	PPMV @ 15% O2	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	Carbon Monoxide	Good Combustion Practices and burning clean fuels (NG)	15.00	PPMV @ 15% O2	3-HOUR AVERAGE
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.110	NATURAL GAS	14,552,539	MMBTU/YR		Carbon Monoxide	Oxidation catalyst	3.50	PPMVD	3-HR ROLLING
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		TURBINE-AUXILLARY BOILER	16.110	178200	-	MMBTU/HR		Carbon Monoxide	Low sulfur natural gas fuel	0.04	LB/MMBTU	
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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-natural gas fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr 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	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1--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	24-HR ROLL AVG EXCEPT STARTUP/SHUTDOWN
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Carbon Monoxide	An oxidation catalyst for CO control for each CTG/HRSG unit, good combustion practices.	4.00	PPM	24-HR ROLL AVG EXCEPT STARTUP/SHUTDOWN
COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	COLBERT	AL	9/21/2021	Electric Generating Facility		Three 229 MW Simple Cycle Combustion Turbines	15.110	Natural Gas	229	MW		Carbon Monoxide		9.00	PPMVD	3 HOUR AVG / @15% O2
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.110	NATURAL GAS	-			Carbon Monoxide	Oxidization catalyst, good combustion practices and the use of gaseous fuel	9.00	PPMVD	15% O2
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.110	Natural gas	-			Carbon Monoxide	catalytic oxidation and carbon monoxide turndown	10.00	PPMVD @15%O2	3-HOUR AVERAGE, @ LOAD =>50%
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.110	Natural Gas	1,113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Carbon Monoxide	Oxidation Catalyst and good combustion practices	5.00	PPMV @ 15% O2	3-HOURS

Table E-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	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, 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 SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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.	9.00	LB/H	HOURLY EXCEPT DURING SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 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 AT 15%O2; 24-HR ROLL AVG EXC SU/SD
TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	8/31/2022	Electric Generation Facility		Ten Simple Cycle NG Turbines	15.110	Natural Gas	466	MMBtu/hr	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Carbon Monoxide	oxidation catalyst	5.00	PPMVD @ 15% O2	4-HOUR ROLLING AVERAGE EXCLUDING STA/SHU

Table E-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
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Vent Gas Disposal via Thermal Oxidizer	19.2	Fuel/Process Gas	6	MMBtu/hr	The Liquefaction Plant will utilize a thermal oxidizer (EU 13) to control off-gas emissions from the condensate tanks EUs 21 and 22 and associated loading system EU 23 through the use of a capture and recovery vapor balance system.	Carbon Monoxide	Proper Equipment Design; Good Combustion Practices	0.082	LB/MMBTU	3-HOURS
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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.	EUEMGD	17.11	Diesel	4474.2	KW	EUEMGD-A 2,206 HP diesel-fueled emergency engine manufactured after 2006 serving a 1,500 kW generator with associated fuel oil tank. The engine generator is used to charge the batteries in the uninterruptible power supply battery system and to facilitate operations during idling of the plant for routine maintenance checks and readiness testing.	Carbon Monoxide	Good combustion practices and will be NSPS compliant.	3.5	G/KW-H	HOURLY

Table E-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	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/psnty/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; (3) Siemens		(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	
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	

Table E-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
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		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	
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	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	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
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	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	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	-		
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)	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)	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

Table E-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
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
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		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 E-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
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		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
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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-natural gas fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Volatile Organic Compounds (VOC)	Good combustion practices	5	LB/H	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1--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	PPM	HOURLY EXCEPT STARTUP SHUTDOWN
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.11	NATURAL GAS	-			Volatile Organic Compounds (VOC)	Oxidization catalyst, good combustion practices and the use of gaseous fuel	1.7	PPMVD	
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.11	Natural gas	-			Volatile Organic Compounds (VOC)	Good combustion practices	-		
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.21	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS

Table E-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
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.11	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Four Combined Cycle Gas-Fired Turbines	15.21	Natural Gas	384	MMBtu/hr	EUs 7 - 10 are combined cycle gas turbines used for power generation at LNG facility	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.11	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.11	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Volatile Organic Compounds (VOC)	Good combustion practices.	5	LB/H	HOURLY EXCEPT DURING SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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	PPM	PPMVD AT 15%O2; HOURLY EXC SU/SD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.21	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Volatile Organic Compounds (VOC)	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.	3	PPM	PPMVD AT 15%O2; HOURLY EXC SU/SD. CC MOD

Table E-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
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. â€¢ One (1) 3,000 gallon emergency generator diesel storage tank. â€¢ One (1) 500 gallon firewater pump diesel storage tank. â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank. â€¢ Lubricating oil storage tanks. â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. â€¢ One (1) 3,000 gallon emergency generator diesel storage tank. â€¢ One (1) 500 gallon firewater pump diesel storage tank. â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank. â€¢ Lubricating oil storage tanks. â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas	Combustion Turbine without Duct Burner	15.21	Natural Gas	3509	MMBtu/hr		Volatile Organic Compounds (VOC)		1	PPMDV	CORRECTED TO 15% O2
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. â€¢ One (1) 3,000 gallon emergency generator diesel storage tank. â€¢ One (1) 500 gallon firewater pump diesel storage tank. â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank. â€¢ Lubricating oil storage tanks. â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). â€¢ One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. â€¢ One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. â€¢ One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. â€¢ Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. â€¢ One (1) 3,000 gallon emergency generator diesel storage tank. â€¢ One (1) 500 gallon firewater pump diesel storage tank. â€¢ One (1) 35,000 gallon 19% aqueous ammonia storage tank. â€¢ Lubricating oil storage tanks. â€¢ Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). â€¢ One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. â€¢ One (1) 6.4 MMBtu/hr natural gas-fired fuel gas	Combustion Turbine With Duct Burner	15.21	Natural Gas	4367	MMBtu/hr		Volatile Organic Compounds (VOC)		2	PPMDV	CORRECTED TO 15% O2
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		COMBINED CYCLE TURBINE	15.21	NATURAL GAS	-			Volatile Organic Compounds (VOC)	OXIDATION CATALYST	1	PPMVD	3-HR ROLLING
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.11	NATURAL GAS	14552539	MMBTU/YR		Volatile Organic Compounds (VOC)	Oxidation catalyst	1.5	PPMVD	3-HR ROLLING

Table E-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	

Table E-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
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

Table E-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
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
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)

Table E-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
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.
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	

Table E-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
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	
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 E-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
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		

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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
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

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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	
NACERO PENWELL FACILITY	NACERO TX 1 LLC	ECTOR	TX	11/17/2021	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.		TURBINE	15.110	NATURAL GAS	0			Carbon Dioxide Equivalent (CO2e)	good combustion practices and the use of gaseous fuel	0		
LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	CALCASIEU PARISH	LA	9/3/2020	A greenfield facility to liquefy and export natural gas.		Turbines (EQT0020 - EQT0031)	15.110	Natural gas	0			Carbon Dioxide Equivalent (CO2e)	Low carbon fuels Energy efficient designs and operation	0		
LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	KENAI PENNINSULA BOROUGH	AK	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.		Six Simle Cycle Gas-Fired Turbines	15.110	Natural Gas	1113	MMBtu/hr	EUs 1 - 6 are simple cycle gas turbines used for gas compression at LNG facility	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and burning clean fuels (natural gas)	117.1	LB/MMBTU	3-HOURS
TENNESSEE VALLEY AUTHORITY - JOHNSONVILLE COMBUSTION TURBINE	TENNESSEE VALLEY AUTHORITY	HUMPHREYS	TN	8/31/2022	Electric Generation Facility		Ten Simple Cycle NG Turbines	15.110	Natural Gas	465.8	MMBtu/hr	465.8 MMBtu/hr per individual turbine 4658.0 MMBtu/hr total Aeroderivative	Carbon Dioxide Equivalent (CO2e)	Efficient turbine operation and good combustion practices	120	LB/MMBTU	
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1--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)		430349	T/YR	12-MO ROLLING TIME PERIOD
LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	1/7/2021	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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2--A nominally rated 667 MMBTU/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Carbon Dioxide Equivalent (CO2e)		430349	T/YR	12-MO ROLLING TIME PERIOD
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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/H natural gas-fired simple cycle CTG	15.110	Natural gas	667	MMBTU/H	A nominally rated 667MMBtu/hr, natural gas-fired simple cycle CTG. The CTG will utilize DLNB and good combustion practices.	Carbon Dioxide Equivalent (CO2e)		318404	T/YR	12-MO ROLLING TIME PERIOD

Table E-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
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG1- 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)		430349	T/YR	12-MO ROLLING TIME PERIOD; DUR. ALL MODE
LBWL-ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	EATON	MI	12/20/2022	Natural gas combined-cycle power plant	The proposed new plant will be replacing the electrical generating capacity of both BWLâ€™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	15.210	Natural gas	667	MMBTU/H	EUCTGHRSG2- A nominally rated 667 MMBtu/hr natural gas-fired CTG coupled with a 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 DLNB, SCR, and oxidation catalyst.	Carbon Dioxide Equivalent (CO2e)		430349	T/YR	12-MO ROLLING TIME PERIOD
HILLTOP ENERGY CENTER, LLC	HILLTOP ENERGY CENTER, LLC	GREENE	PA	4/12/2017	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst. One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank. One (1) 500 gallon firewater pump diesel storage tank. One (1) 35,000 gallon 19% aqueous ammonia storage tank. Lubricating oil storage tanks. Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR). One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler. One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater. One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine. One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine. Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators. One (1) 3,000 gallon emergency generator diesel storage tank.	Combustion Turbine without Duct Burner	15.210	Natural Gas	3509	MMBtu/hr		Carbon Dioxide Equivalent (CO2e)		879	LB	MWH (GROSS)
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	
UNIT 5	NRG CEDAR BAYOU LLC	CHAMBERS	TX	3/17/2021	UNIT 5		SIMPLE CYCLE TURBINE	16.110	NATURAL GAS	14552539	MMBTU/YR		Carbon Dioxide Equivalent (CO2e)	Low sulfur natural gas fuel	0		

Table E-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 F. 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

EXPEDITED PERMITTING PROGRAM – APPLICATION FOR ENTRY TO PROGRAM FOR AIR PERMITS

EPD Use Only

Date Received: ____________ **Application No.** ____________

To be eligible for expedited review, this application form must be accompanied by the complete permit application for the type of air permit being requested.

1. Contact Information

Facility Name: Talbot Energy Facility
AIRS No. (if known): 04-13- 263 - 00013
Contact Person: Courtney Adcock Title: Facility Air Permit Contact
Telephone No.: 770-270-7678 Alternate Phone No.: ____________
Email Address: courtney.adcock@opc.com

If EPD is unable to contact me, please contact the alternate contact person:
Contact Person: Bob Brinkman Title: Director of Environmental Affairs
Telephone No.: 706-848-5527 Alternate Phone No.: ____________
Email Address: bob.brinkman@opc.com

On Page 2 of this form, please check the appropriate box for which type of air permit you are requesting expedited review.

I have read the Expedited Review Program Standard Operating Procedures and accept all of the terms and conditions within. I have participated in the required pre-application meeting with EPD. I understand that it is my responsibility to ensure an application of the highest quality is submitted and to address any requests for additional information by the deadline specified. I understand that submittal of this request form is not a guarantee that expedited review will be granted.

Signature: Courtney Adcock Date: 9/5/2023

2. Applying For Which Type Of Permit: (Please Check Appropriate Box)

Expedited Review Fees for Air Permits	
Permit Type – Please Check One	**Expedited Review Fee*** **as of March 1, 2021**
☐ Generic Permit: Concrete Batch Plant – Minor Source	$1,250
☐ Generic Permit: Concrete Batch Plant – Synthetic Minor Source	$1,875
☐ Generic Permit: Hot Mix Asphalt Plant – Synthetic Minor Source	$2,500
☐ Minor Source Permit (or Amendment)	$3,750
☐ Synthetic Minor Permit (or Amendment)	$5,000
☐ Major Source SIP Permit not subject to PSD or 112(g)	$7,500
☐ Title V 502(b)(10) Permit Amendment	$5,000
☐ Title V Minor Modification with Construction	$5,000
☐ Title V Significant Modification	$7,500
☐ Major Source SIP Permit subject to 112(g) but not subject to PSD	$18,750
☐ PSD Permit (or Amendment) not subject to NAAQS and/or PSD Increment Modeling	$18,750
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling but not subject to Modeling for $PM_{2.5}$, NO_2, or SO_2	$25,000
☑ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2	$31,250
☐ PSD Permit (or Amendment) subject to NAAQS and/or PSD Increment Modeling for $PM_{2.5}$, NO_2, or SO_2 and also impacting a Class I Area	$37,500
☐ Nonattainment NSR Review Permit (or Amendment)	$50,000
* Do not send fee payment with this form. Upon acceptance of application for the expedited permit program, EPD will notify you and an invoice will appear on GECO. Fees must be paid via check to "Georgia Department of Natural Resources" within ten (10) business days of acceptance.	

3. Comments.

This section is optional. Applicants may use this field to include specific comments or requests for EPD consideration. For example, the applicant may use this field to request a public hearing or to remind EPD of review time needs and/or expectations that may differ from the time frames in the procedures.

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: Talbot Energy Facility
AIRS No. (if known): 04-13- 263 - 00013
Facility Location: Street: 9125 Cartledge Road
City: Box Springs Georgia Zip: 31801 County: Talbot
Is this facility a "small business" as defined in the instructions? Yes: ☐ No: ☒

2. Facility Coordinates

Latitude: 32° 35' 17" **NORTH** Longitude: -84° 41' 32" **WEST**
UTM Coordinates: 716700 **EAST** 3608000 **NORTH** **ZONE** 16

3. Facility Owner

Name of Owner: Oglethorpe Power Corporation
Owner Address Street: 2100 East Exchange Place
City: Tucker State: Georgia Zip: 30084

4. Permitting Contact and Mailing Address

Contact Person: Courtney Adcock Title: Facility Air Permit Contact
Telephone No.: 770-270-7678 Ext. ______ Fax No.: ______
Email Address: courtney.adcock@opc.com
Mailing Address: Same as: Facility Location: ☐ Owner Address: ☒ Other: ☐
If Other: Street Address: ______
City: ______ State: ______ Zip: ______

5. Authorized Official

Name: Jeffrey Swartz Title: Senior Vice President of Plant Operations
Address of Official Street: 2100 East Exchange Place
City: Tucker State: Georgia Zip: 30084

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: [signature] Date: 9/6/2023

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.: 4911-263-0013-V-07-0

☐ 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, Inc.

Name of Contact: Justin Fickas

Telephone No.: 678.441.9977, ext. 228 Fax No.:

Email Address: jfickas@trinityconsultants.com

Mailing Address: Street: 1230 Peachtree St NE, 300 Promenade

City: Atlanta State: Georgia Zip: 30309

Describe the Consultant's Involvement:

Trinity provided Oglethorpe Power Corporation with air permitting assistance including draft permit application, potential emissions calculations, SIP form completion, modeling, and general consulting guidance throughout the process.

9. **Submitted Application Forms:** Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
1	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
1	3.00 Air Pollution Control Devices (APCD)
	3.01 Scrubbers
	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data

	5.00	Monitoring Information
	6.00	Fugitive Emission Sources
1	7.00	Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: Q1 2024

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[1]		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	250	250	474.35	<474.35
Nitrogen oxides (NOx)	250	250	957.97	<957.97
Particulate Matter (PM) (filterable only)	<250	<250	70.54	<70.54
PM <10 microns (PM10)	<250	<250	233.78	<233.78
PM <2.5 microns (PM2.5)	<250	<250	233.78	<233.78
Sulfur dioxide (SO_2)	<100	<100	41.05	<41.05
Volatile Organic Compounds (VOC)	250	<250	90.15	<90.15
Greenhouse Gases (GHGs) (in CO2e)	100,000	100,000	1,760,859	<1,760,859

Total Hazardous Air Pollutants (HAPs)	<25	<25	8.77	<8.77
Individual HAPs Listed Below:				
Formaldehyde (Max Single HAP)	<10	<10	2.01	<2.01

1. The potential facility emissions with respect to the various permitting thresholds are utilized above for the current facility emissions.

14. 4-Digit Facility Identification Code:

SIC Code: 4911 SIC Description: Electric Services

NAICS Code: 221112 NAICS Description: Fossil Fuel Electric Power Generation

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.

Talbot Energy Facility is proposing to modify four existing simple-cycle turbines (Source Codes: T1-T4), which currently combust natural gas, to also combust fuel oil. The facility is proposing to add two fuel oil storage tanks, a diesel fire pump and water tank, to provide water for fire suppression in case of emergency.

16. Additional information provided in attachments as listed below:

Attachment A - Area Map

Attachment B - NSR Evaluation

Attachment C - PTE Calculations

Attachment D - Control Cost Analyses

Attachment E - RBLC Search Results

Attachment F - SIP Permit Application Forms

Attachment G - Volume II - Modeling

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: N/A

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:**

OPC will obtain a stormwater construction permit for the construction of storage tanks if needed.

19. List requested permit limits including synthetic minor (SM) limits.

Refer to Narrative for requested limits associated with this project.

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: Courtney Adcock

Fee Contact email address: courtney.adcock@opc.com

Fee Contact phone number: 770-270-7678

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: Talbot Energy Facility **Date of Application:** August 2023

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
T1	Combustion Turbine 1	Siemens-Westinghouse V84.2 Simple Cycle CT	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 108 MW
T2	Combustion Turbine 2	Siemens-Westinghouse V84.2 Simple Cycle CT	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 108 MW
T3	Combustion Turbine 3	Siemens-Westinghouse V84.2 Simple Cycle CT	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 108 MW
T4	Combustion Turbine 4	Siemens-Westinghouse V84.2 Simple Cycle CT	Currently combusts Natural Gas, soon to combust Fuel Oil. Produces a power output of 108 MW
ST2	Fuel Oil Storage Tank 2	TBD	Fuel Oil storage for the modified turbines
ST3	Fuel Oil Storage Tank 3	TBD	Fuel Oil storage for the modified turbines
FP1	Fire Pump Engine	TBD	Diesel Fire Pump for fire suppression

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	1,180 for NG, 1,365 for FO	N/A	Q1/2024	Q1/2024	Modified Q1/2024 for fuel oil capacity
T2	Dry-Low NOx Burner	N/A	1,180 for NG, 1,365 for FO	N/A	Q1/2024	Q1/2024	Modified Q1/2024 for fuel oil capacity
T3	Dry-Low NOx Burner	N/A	1,180 for NG, 1,365 for FO	N/A	Q1/2024	Q1/2024	Modified Q1/2024 for fuel oil capacity
T4	Dry-Low NOx Burner	N/A	1,180 for NG, 1,365 for FO	N/A	Q1/2024	Q1/2024	Modified Q1/2024 for fuel oil capacity

[1] This column does not have to be completed for natural gas only fired equipment.

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	4,425,000	MMBtu/yr	Varies	Varies	1,180	N/A	N/A		<0.001	N/A	N/A	N/A
T1	Fuel Oil	614,250	MMBtu/yr	Varies	Varies	1,365	N/A	N/A		0.0015	N/A	N/A	N/A
T2	Natural Gas	4,425,000	MMBtu/yr	Varies	Varies	1,180	N/A	N/A		<0.001	N/A	N/A	N/A
T2	Fuel Oil	614,250	MMBtu/yr	Varies	Varies	1,365	N/A	N/A		0.0015	N/A	N/A	N/A
T3	Natural Gas	4,425,000	MMBtu/yr	Varies	Varies	1,180	N/A	N/A		<0.001	N/A	N/A	N/A
T3	Fuel Oil	614,250	MMBtu/yr	Varies	Varies	1,365	N/A	N/A		0.0015	N/A	N/A	N/A
T4	Natural Gas	4,425,000	MMBtu/yr	Varies	Varies	1,180	N/A	N/A		<0.001	N/A	N/A	N/A
T4	Fuel Oil	614,250	MMBtu/yr	Varies	Varies	1,365	N/A	N/A		0.0015	N/A	N/A	N/A

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Pipeline Quality Natural Gas						
Fuel Oil	TBD	TBD	TBD	TBD	TBD	TBD

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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
ST2	Fuel Oil Storage Tank	1,580,000	ULSD	0.004 psia	Ambient	TBD	Q1/2024	Fixed	N/A
ST3	Fuel Oil Storage Tank	1,580,000	ULSD	0.004 psia	Ambient	TBD	Q1/2024	Fixed	N/A

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	
WI10	T1	Water Injection	Q1/2024	TBD	N/A	N/A	1006	N/A
WI20	T2	Water Injection	Q1/2024	TBD	N/A	N/A	1006	N/A
WI30	T3	Water Injection	Q1/2024	TBD	N/A	N/A	1006	N/A
WI40	T4	Water Injection	Q1/2024	TBD	N/A	N/A	1006	N/A
LNB1	T1	Low NOx Burner	2002/Q12024	Siemens-Westinghouse	N/A	N/A	1008	N/A
LNB2	T2	Low NOx Burner	2002/Q12024	Siemens-Westinghouse	N/A	N/A	1008	N/A
LNB3	T3	Low NOx Burner	2002/Q12024	Siemens-Westinghouse	N/A	N/A	1008	N/A
LNB4	T4	Low NOx Burner	2002/Q12024	Siemens-Westinghouse	N/A	N/A	1008	N/A

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	
WI10	NOx	60%	N/A	TBD	Calculated	TBD	TBD	N/A
WI20	NOx	60%	N/A	TBD	Calculated	TBD	TBD	N/A
WI30	NOx	60%	N/A	TBD	Calculated	TBD	TBD	N/A
WI40	NOx	60%	N/A	TBD	Calculated	TBD	TBD	N/A
LNB1	NOx	50%	N/A	N/A	Calculated	N/A	N/A	N/A
LNB2	NOx	50%	N/A	N/A	Calculated	N/A	N/A	N/A
LNB3	NOx	50%	N/A	N/A	Calculated	N/A	N/A	N/A
LNB4	NOx	50%	N/A	N/A	Calculated	N/A	N/A	N/A

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	WI10, WI20, WI30, WI40	T1-T4	CO	N/A	198.74	N/A	388.32	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	NOx	N/A	917.28	N/A	627.29	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	Total PM	N/A	92.82	N/A	142.13	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	Total PM10	N/A	92.82	N/A	142.13	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	Total PM2.5	N/A	92.82	N/A	142.13	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	SO2	N/A	8.25	N/A	7.17	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	VOC	N/A	38.00	N/A	50.36	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	CO2e	N/A	889,135	N/A	1,253,010	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	Lead	N/A	0.076	N/A	0.017	Emission Factors
T1-T4	WI10, WI20, WI30, WI40	T1-T4	Sulfuric Acid Mist	N/A	0.825	N/A	0.72	Emission Factors
T1-T6	WI10, WI20, WI30, WI40	T1-T6	Total HAP	N/A	17.13	N/A	8.51	Emission Factors
ST2	N/A	ST2	VOC	N/A	0.11	N/A	0.47	AP-42 Section 7.1
ST2	N/A	ST2	Total HAP	N/A	9.6E-03	N/A	4.2E-02	AP-42 Section 7.1
ST3	N/A	ST3	VOC	N/A	0.11	N/A	0.47	AP-42 Section 7.1
ST3	N/A	ST3	Total HAP	N/A	9.6E-03	N/A	4.2E-02	AP-42 Section 7.1
FP1	N/A	FP	SO2	N/A	0.93	N/A	0.23	Emission Factors
FP1	N/A	FP	NOx	N/A	3.06	N/A	0.77	Emission Factors
FP1	N/A	FP	CO	N/A	1.86	N/A	0.46	Emission Factors

FP1	N/A	FP	Total PM	N/A	0.065	N/A	0.016	Emission Factors
FP1	N/A	FP	Total PM10	N/A	0.065	N/A	0.016	Emission Factors
FP1	N/A	FP	Total PM2.5	N/A	0.065	N/A	0.016	Emission Factors
FP1	N/A	FP	VOC	N/A	0.11	N/A	0.028	Emission Factors
FP1	N/A	FP	Sulfuric Acid Mist	N/A	0.093	N/A	0.023	Emission Factors
FP1	N/A	FP	CO2e	N/A	529	N/A	132	Emission Factors

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

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	Flow Rate (acfm) Maximum
Refer to Volume II of this Application for Modeling Information										

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.

Refer to Volume II of this Application for Modeling Information

Facility Name: Talbot Energy Facility **Date of Application:** August 2023

FORM 7.00 AIR MODELING INFORMATION: Chemicals Data

Chemical	Potential Emission Rate (lb/hr)	Toxicity	Reference	MSDS Attached
Refer to Volume II of this Application for Modeling Information				
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PSD PERMIT APPLICATION
Volume II – Modeling Report

Fuel Oil Conversion Project

Oglethorpe Power Corporation

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August 2023

Project 221101.0252

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1. EXECUTIVE SUMMARY

Talbot Energy Facility, owned and operated by Oglethorpe Power Corporation (OPC), is a peaking power plant with six simple cycle combustion turbines (producing a nominal total of 648 megawatts), three fuel gas heaters, and one diesel fuel storage tank. Four of the six combustion turbines (CTs) (Source Codes: T1, T2, T3, and T4) and all three fuel gas heaters (Source Codes: H1, H2, and H3) fire natural gas only. The remaining two CT units (Source Codes: T5 and T6) use natural gas as a primary fuel with the ability to fire distillate fuel oil as a back-up fuel. The formation of nitrogen oxides (NO_X) emissions during periods of natural gas combustion is controlled through the use of dry Low-NO_X (DLN) combustors for all six of the combustion turbines, and water injection is used to minimize the formation of NO_X emissions during periods of low sulfur diesel fuel oil firing for units T5 and T6. Low NO_X burners minimize the formation of NO_X emissions from the three fuel gas heaters.

The facility is proposing to modify four of the existing simple cycle turbines (Source Codes: T1, T2, T3, and T4) to allow combustion of either natural gas or ultra-low sulfur diesel fuel. As is the case with units T5 and T6, units T1 through T4 will continue to operate primarily on natural gas with fuel oil used as a back-up fuel. The project will also include installation of two (2) new fuel oil storage tanks to accommodate fuel oil operations on combustion turbines T1-T4 and one (1) new diesel-fired emergency fire water pump engine.

The proposed project will require a Prevention of Significant Deterioration (PSD) permit as a major modification to an existing major source.[1] Project-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 ($PM_{2.5}$), 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

OPC is proposing the addition of fuel oil combustion capability for four of the facility's six existing combustion turbines to enhance system reliability and to provide support and meet demand during times of natural gas supply curtailment and interruption. This project requires physical modifications to each of the four turbines to add fuel oil burners, installation of fuel oil storage capacity, and the addition of an emergency diesel-fired fire water pump engine. OPC is requesting permit conditions limiting the total annual hours of operation for each modified combustion turbine to no more than 4,200 hours per 12-month rolling period and limiting fuel oil firing to no more than 450 hours per 12-month rolling period per unit. OPC is also requesting a permit condition limiting annual operation for the emergency fire pump engine to no more than

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[1] The facility is currently a PSD major source, driven largely by facility NO_X emissions. 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.

500 hours per 12-month rolling period. More detail regarding the proposed project is provided in Section 2 of Volume I of this application.

1.2 Permitting and Regulatory Requirements

OPC is submitting this construction and operating permit application, in accordance with the PSD permitting requirements, to request authorization to modify four of the facility's six existing combustion turbines, specifically Turbines 1-4, and operate them as modified. Since the facility is a major source under the PSD permitting program, emission increases from the proposed project must be evaluated and compared to the SER thresholds for regulated pollutants under the PSD program. OPC has evaluated emissions increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), lead (Pb), 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.[3]

Table 1-1. Proposed Project Emissions Increases

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	9.96	42.68	0.01	32.73	--	32.73	25	Yes
Total PM_{10}	34.33	142.13	0.02	107.81	--	107.81	15	Yes
Total $PM_{2.5}$	34.33	142.13	0.02	107.81	--	107.81	10	Yes
SO_2	1.50	7.17	0.23	5.90	--	5.90	40	No
NO_X	73.90	627.29	0.77	554.16	--	554.16	40	Yes
VOC	6.37	50.36	0.97	44.97	--	44.97	40	Yes
CO	74.60	388.32	0.46	314.18	--	314.18	100	Yes
CO_2e	298,178	1,253,010	132.28	954,964	--	954,964	75,000	Yes
Lead	--	1.7E-02	--	1.7E-02	--	1.7E-02	0.60	No
Sulfuric Acid Mist	0.15	0.72	0.02	0.59	--	0.59	7.00	No

1. The four existing site turbines are the modified units with respect to this PSD assessment.
2. The two fuel oil storage tanks and diesel fire pump are new units with respect to this PSD assessment.
3. Emissions Increase from New and Modified Units (tpy) = New Unit Potential Emissions (tpy) + Modified Unit Potential 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)

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

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

[3] 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.

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 and Class II SILs for all applicable averaging periods.
- Ambient CO impacts from the project in the form of the standard are below the Class II SILs for all applicable averaging periods, for all operating scenarios evaluated.
- Ambient NO_2 impacts from the project in the form of the standard are below the Class I SILs 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, for multiple operating scenarios. Subsequent modeling demonstrated that OPC's operations do not cause or contribute to any violation of the 1-hr NO_2 National Ambient Air Quality Standard (NAAQS).
- An evaluation of plume blight, using the VISCREEN model, showed no issues with visibility-based impacts for the closest nearby identified Class II visibility area of concern near the facility.
- Toxic Air Pollutant (TAP) modeled impacts are below applicable "Allowable Ambient Concentration" provided by GA EPD.

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 exceed any PSD Increment for PM_{10}, $PM_{2.5}$, CO, or NO_2.

1.4 Application Contents

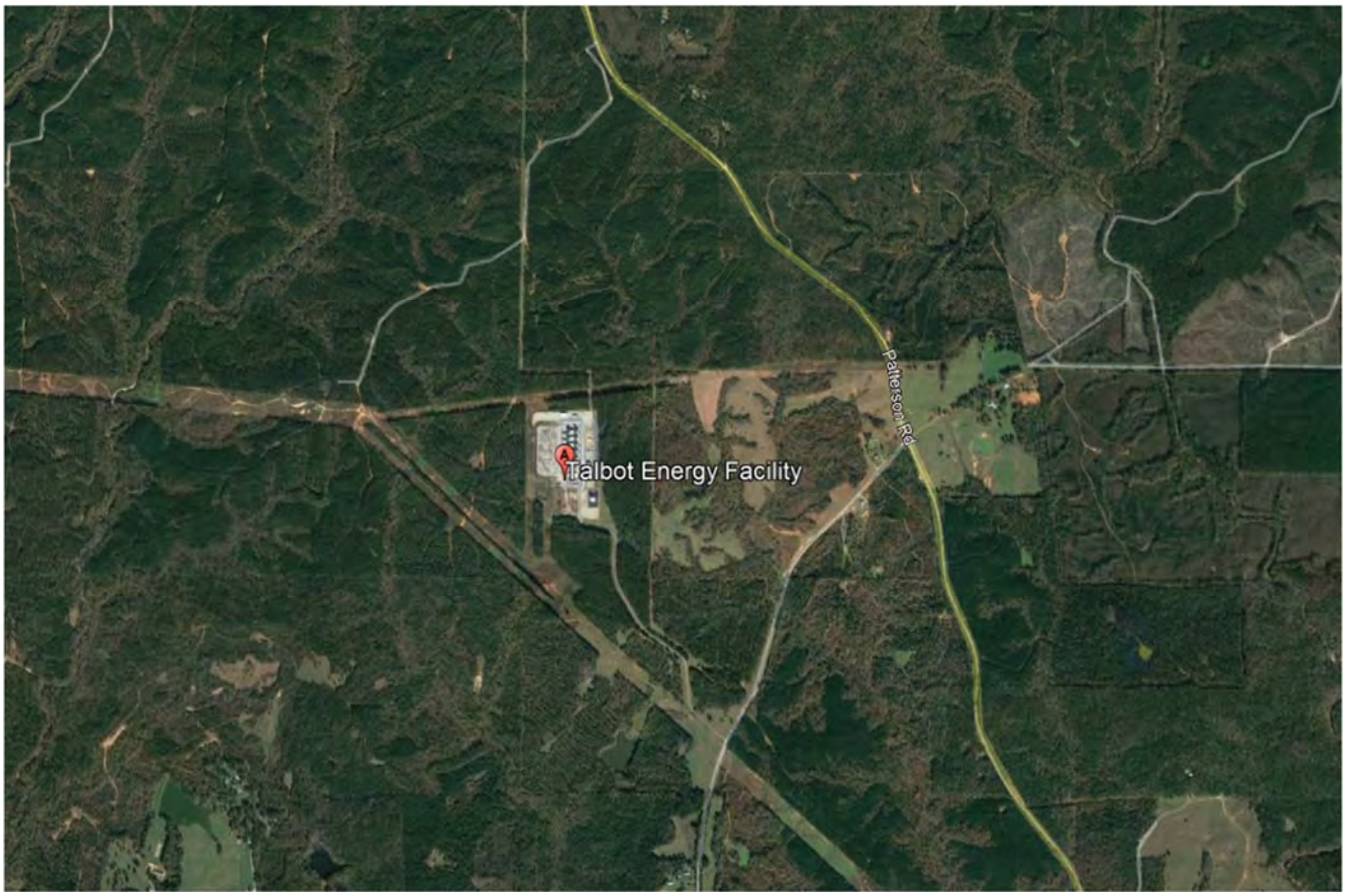
Volume II of this permit application is organized as follows:

- 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 notifications to the Federal Land Managers (FLMs);
- 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

Figure 2-1. provides a map of the area surrounding the proposed project location. The approximate central Universal Transverse Mercator (UTM) coordinates of the facility (centered around the emissions sources) are 716.591 kilometers (km) East and 3,608.001 km North in Zone 16 (NAD 83). The area surrounding the facility is predominantly rural.

Figure 2-1. Project Site Location Map



The property boundary area (ambient air boundary) of the facility is completely fenced and access to the entirety of the property is via the access road at the south end of the property. The fence line boundary of the facility is shown in **Figure 2-2** (yellow line visible drawn around the facility).

Figure 2-2. Facility Ambient Air Boundary and General Site Layout

2.1 Description of Proposed Project

OPC is proposing the addition of fuel oil combustion capability for four of the facility's six existing combustion turbines, specifically Turbines T1-T4, to enhance system reliability and to provide support and meet demand during times of natural gas supply curtailment and interruption. This project requires physical modifications to each of the four turbines to add fuel oil burners, installation of fuel oil storage capacity, and the addition of an emergency diesel-fired fire pump engine. OPC proposes to continue operating the existing DLN burners on the turbines during periods of gas combustion and proposes to install and operate a water-injection system that will operate during periods of fuel oil combustion. OPC is requesting permit conditions limiting the total annual hours of operation for each modified combustion turbine to no more than 4,200 hours per 12-month rolling period and limiting fuel oil firing to no more than 450 hours per 12-month rolling period per unit. OPC is also requesting a permit condition limiting annual operation for the emergency fire pump engine to no more than 500 hours per 12-month rolling period. The proposed fuel oil storage capacity of each of the two new tanks will be 1,600,000 gallons, with a conservatively estimated fuel oil throughput of 8.775 million gallons per year.

OPC proposes to begin this project in the first quarter of 2024. Therefore, OPC is submitting this application into EPD's Expedited Permitting Program to ensure that a final permit is obtained by February 2024.

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[4]:

- *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, June 2022)
- AERMOD Implementation Guide (EPA, June 2022)
- 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)
- *Guidance for Ozone and Fine Particulate Matter Modeling* (EPA, Memorandum from Mr. Richard A. Wayland, July 29, 2022)
- *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, 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 $PM_{2.5}$ 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).

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 promulgated 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. Talbot County, where the facility is located, is currently designated as "attainment" or "unclassifiable" for all criteria pollutants.[5]

The proposed project will be considered a major modification under PSD since the proposed project emissions increases for certain criteria pollutants are expected to exceed their respective PSD SERs.

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[4] Modeling protocol submitted to the Georgia EPD on April 03, 2023, with comments received from the Georgia EPD on May 04, 2023. Copies of these documents can be found in Appendix C.

[5] 40 CFR 81.311

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 $PM_{2.5}$. The ozone-based impacts of the project's NO_X and VOC emissions increases 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 calculated emissions increases for CO, NO_2, PM_{10} and $PM_{2.5}$ would exceed certain 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 ($\mu g/m^3$)	Primary NAAQS ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)
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 $\mu g/m^3$, and an annual SIL of 0.2 $\mu g/m^3$. However, the guidance indicated that the permitting authority had the discretion to continue to utilize the previously established annual SIL of 0.3 $\mu g/m^3$. 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 <u>highest</u> design concentrations out of all given modeling years for each pollutant-averaging time is compared to the SIL level shown in Table 3-1. 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. 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/Increment analysis is required. For PM_{10}, the impacts were evaluated on a year-by-year basis for comparison to the SIL.

As detailed further in Section 4.8.6, 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 NO_X emissions, in accordance with the February 2019 Georgia EPD MERPs guidance. Addition of secondary $PM_{2.5}$ to any PM_{10} SIL results was also considered, but would have no impact/bearing on the overall modeled impacts compared to the PM_{10} SILs.

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 using a concatenated meteorological data set basis for comparison to the SIL, since evaluation of H1H impacts for 1-hr and 8-hr averages in AERMOD will not trigger any averaging for this pollutant/averaging period.

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, NAAQS and PSD Increment analyses are required for that pollutant and averaging period, as applicable, to demonstrate that the facility neither causes nor contributes to any exceedances.

3.2 Ambient Background Data

The Georgia EPD publishes background concentration values on their website and the data for those background monitors as specified by the Georgia EPD was utilized, with exceptions noted below. [6] The chosen background values are shown in Table 3-2.

The Macon, Georgia ozone monitoring location (Georgia Forestry Commission) was chosen based on the surrounding location of the monitors which is primarily rural and is located east of the metropolitan area of Macon.[7] This is a similar geographic location of the Talbot Energy Facility, located to the east of a major metropolitan area (Columbus). Although there is an ozone monitor located in the Columbus area, that monitor is located in a more urban environment, and not representative of the more rural setting of the Talbot Energy Facility east of the metropolitan area of Columbus. Use of background data from this monitor should be sufficiently conservative for this analysis.

In Table 3-2, NO_2 data are based on statewide background concentration values as provided by the Georgia EPD ambient background data posted on their website. The ozone background data is representative of 2020-2022 design value data, as obtained from the EPA Air Data website, for the Georgia Forestry Commission monitoring location.

[6] https://epd.georgia.gov/georgia-background-data

[7] Monitor locations obtained from U.S. EPA AirData: https://www.epa.gov/outdoor-air-quality-data/monitor-values-report

Table 3-2. Selected Background Concentrations

PSD Pollutant	Averaging Period	Monitor Background Concentration (μg/m³)	Metric	Monitor Location
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	
Ozone	8-hour	58 (ppb)	Annual 4th highest daily maximum 8-hr value, 3-yr average	Georgia Forestry Commission, 5645 Riggins Mill Road, Dry Branch, Georgia

3.3 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, 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, and PM_{10} are provided in 40 CFR §52.21(i)(5)(i) and are listed in Table 3-1. Modeled impacts for all pollutants of interest were less than their applicable SMCs.

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 increase in emissions 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 $PM_{2.5}$. Therefore, for this project, the existing ambient background monitoring network for $PM_{2.5}$ in the State of Georgia will be sufficient.

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, an ambient ozone impact analysis is not required unless a project's emissions increase is greater than 100 tpy of VOC or NO_X. As this project's increase in emissions is greater than 100 tpy of NO_X, an ozone impacts analysis is conducted through evaluation of the MERPs.

EPA has issued guidance specifying a SIL value for ozone of 1 ppb, and has developed a 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.[8] 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 4.8.6 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)[9]:

- Cohutta Wilderness – 249.82 km
- Bradwell Bay Wilderness – 261.54 km
- Saint Marks Wilderness – 273.41 km
- Okefenokee Wilderness – 277.4 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.[10]

Notifications were submitted to the appropriate FLMs for all Class I areas located within 300 km of the facility requesting concurrence with a finding regarding the requirement for AQRV analysis for this project.[11] 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 and FLM notifications conducted can be found in Appendix B.

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[8] *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).

[9] 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

[10] 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.

[11] 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 was provided to the Georgia EPD.

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 these Significance Analyses. A screening procedure was utilized evaluating an array of receptors located 50 km from the facility at 1-degree intervals for a full 360 degrees, creating a ring of hypothetical receptors at a 50 km distance from the facility to compare project emission increase impacts to those receptors at 50 km.[12] Significance results from those receptors 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 $PM_{2.5}$.[13]

Table 3-3. Class I Significant Impact Levels and Increment Thresholds

Pollutant	Averaging Period	Class I SIL (µg/m³)	Class I PSD Increment (µg/m³)
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, the only pollutant (and averaging period) to exceed the Class II SIL was 1-hr NO_2 for modeling runs including startup and shutdown[14]. No other pollutants ($PM_{2.5}$, PM_{10}, and CO) exceeded the Class II SILs. No pollutants exceeded the Class I SILs, as referenced in Section 3.5 and 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 NO_2 NAAQS. Significance evaluations of startup and shutdown operation scenarios using fuel oi showed showed levels above the SIL that extended to 50 km from the facility. Modeling inventory information was compiled as described in the following sections.

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 a 50 km radius of the facility. As a result, fifteen (15) counties were identified in Georgia, including Chattahoochee County, Crawford County, Harris County, Macon County, Marion County, Meriwether County, Muscogee County, Pike County, Schley County, Stewart County, Talbot County, Taylor County, Troup County, Upson County, and Webster County.

[12] Consistent with EPD guidance, this assumes that all applicable FLMs have determined that no AQRV analyses are required for the project.

[13] *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).

[14] Two startup/shutdown periods were evaluated for Class II SIL comparison: 4am startup and 10am startup.

The Georgia EPD source list was queried and evaluated for all counties in Georgia within 50 km of the facility.[15] Only sources within the fifteen counties listed above were evaluated further. Sources that are classified as permit by rule category were excluded. Sources were further filtered by operating status, and all sources that were indicated as shutdown or no-longer in operation were excluded. This list served as the basis of the initial inventory source list.

The EPD PSD modeling inventory tool was queried for all source information within the counties of interest within 50 km of the facility.[16] 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 identified that were included in the PSD modeling inventory but not included in the Georgia EPD source list.

The EPD air permits website was then 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.[17] The permit list was also reviewed for consistency with data provided in the June 2018 EPD permitted source listing. Additionally, these sources were also compared to Google Earth as a third point of criteria to determine if a source was still present and/or in the location specified.

Based on the steps identified above, 53 sources were identified in the initial inventory source list as detailed in Tables D-19 and D-20 of Appendix D.

3.6.2 Development of Refined Inventory Source List

Since levels above SILs were found out to a distance of 50 km for NOx modeling runs of fuel oil including start-up and shutdown, no screening analysis was necessary to evaluate for those sources within 50 km, since all sources within the SIA distance are traditionally included as part of the modeling inventory. However, this initial listing was quite large (53 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. Therefore, those sites were also removed from consideration. For example, automotive body shop type facilities were excluded. Sources with no permit found 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, and the site could not be physically located, then the site was removed from consideration.
- 40 sources were identified as the refined inventory source list as detailed in Table D-21 of 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. 40 sources were identified for additional review, with 29 minor sources specifically identified for which no information was available via EPD's online modeling inventory information. Based on the results of the file review excluded, a few identified sources were excluded from the modeling evaluation for the following reasons:

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[15] https://epd.georgia.gov/list-sources-georgia - last updated June 2018.

[16] https://psd.gaepd.org/inventory/

[17] https://permitsearch.gaepd.org/

- 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. Also, in some instances Georgia EPD indicated the facility in question was no longer an operating facility. After extensive file review at the Georgia EPD, only a limited number of minor sources had enough data available/located from file review, to represent those sources in the modeling inventory.
- 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.

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.[18] The results of the soil and vegetation analysis are discussed in Section 5.4.

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 projects that have no regional airports, state parks, or State Historic Sites located within the project's significant impact area (SIA). The proposed project's modeled impacts are under the SILs for PM_{10}, $PM_{2.5}$, and CO. However, there is a regional airport (Columbus Airport), located within the project's 1-hr NO_2 SIA. Therefore, a Class II visibility assessment was conducted for the Columbus Airport.

While not a requirement under the federal PSD regulations, OPC has included an evaluation of TAP for the facility emission sources as part of this permit application in accordance with Georgia EPD guidelines.[19] The post-project facility-wide potential emissions for each listed TAP were compared to the Minimum Emission Rate (MER) values provided in guidance to determine if modeling for those TAP was required. TAP modeling results are discussed in detail in Section 5.5.

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.

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[18] *U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA 450/2-81-078), 1980.

[19] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May, 2017.

Additional consideration of ozone is discussed further in Section 4 of this report associated with the 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).

4. MODEL SELECTION AND METHODOLOGY

This section includes a summary of the modeling methodology originally presented in the dispersion modeling protocol previously submitted to[20] and approved by[21] the Georgia EPD.

4.1 Model Selection – AERMOD

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 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, OPC utilized 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*.

The latest version (v22112) of the AERMOD modeling system was used to estimate maximum ground-level concentrations in all 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.[22] 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.[23] 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.[24]

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.

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[20] Email from Mr. Justin Fickas (Trinity) to Mr. Byeong Kim (EPD), dated April 03, 2023. A copy of the modeling protocol can be found in Appendix C.

[21] Written approval provided in email correspondence from Mr. Byeong Kim (EPD) to Mr. Justin Fickas (Trinity) dated May 4, 2023 and June 23, 2023. A copy of the modeling protocol response can be found in Appendix C.

[22] 40 CFR Part 51, Appendix W, Guideline on Air Quality Models, Appendix A.1 AMS/EPA Regulatory Model (AERMOD).

[23] Earth Tech, Inc., Addendum to the ISC3 User's Guide, The PRIME Plume Rise and Building Downwash Model, Concord, MA.

[24] 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.

AERMAP (v18081) 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 (v22112) 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.

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). Any sources to be evaluated in this modeling assessment with vertical obstructed releases will be evaluated using the appropriate options for horizontal or capped point sources within AERMOD.

4.2 Modeled Sources

OPC modeled the project-associated sources for the significance analysis. This includes the facility's four simple cycle combustion turbines (T1-T4) that will be modified as part of this project.

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 was performed (cumulative impact analysis). For the cumulative impact analysis, all sources at the facility and the appropriate inventory sources were included. OPC is planning to install an emergency diesel-fired fire pump engine as part of the proposed project; however, the fire pump is not included in the modeling portion of the application as it is an intermittently-operated source and therefore does not need to be included as an emission source as part of the modeling analysis.[25] Additional information regarding the fire pump, is as follows;

1. Emissions from the fire pump can be found in Appendix C of Volume I of this permit application, specifically Table C-35. The fire pump engine is an approximately 455 hp diesel fired unit. While emissions from the unit are estimated at 500 hr/yr, the actual operational run time of the unit will be limited. At 500 hrs/yr NOx emissions from the unit are less than 1 tpy, CO emissions are less than 0.5 tpy, and PM_{10}/$PM_{2.5}$ emissions are less than 0.1 tpy.

2. Testing of the unit will typically be done at least once a calendar quarter for approximately 30 minutes to 1 hour.

3. The fire pump engine will conduct maintenance and readiness testing on an approximately quarterly schedule, although there is no clearly defined schedule.

4. The fire pump engine would not be routinely tested simultaneously with another similar unit.

[25] *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)

5. Permit conditions will be established for the fire pump engine, ensuring hours of operation, and maintaining the emission unit as an emergency unit.

As the operations of the fire pump engine will be 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 model 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 fire pump engine is not included in any modeling evaluations for the facility.

4.3 Receptor Grid and Coordinate System

Modeled concentrations were calculated at ground-level receptors placed along the facility's fence line and on a variable Cartesian receptor grid. Fence line receptors were spaced no further than 50 meters apart. Beyond the fence line, receptors were 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 SIA utilized a minimum 10 km receptor grid from the facility.

Two primary receptor grids were created for the facility modeling in order to evaluate modeled impacts. For all pollutant modeling except for evaluation of 1-hr NO_2 impacts, a 10-km receptor grid of 100 meter spacing was created. Due to the size of the impact area for the 1-hr NO_2 averaging period, a much larger receptor 50-km grid extending from the facility, with receptor spacing of 100 meters out to 10 km, 250 meters from 10 km to 20 km, and 500 meters from 20 km to 50 km from the facility, was utilized to evaluate impacts for all 1-hr NO_2 significance modeling.

In general, the receptors 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 exceed the SIL. The boundary is defined as all areas that are fenced and not accessible to the general public, 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 NAAQS and Increment modeling.

Receptor elevations and hill heights required by AERMOD were determined using the AERMAP terrain preprocessor (version 18081). Terrain elevations from the USGS 1/3-arc second NED were used for AERMAP processing.

In all modeling analysis data files, the location of emission sources, structures, and receptors are represented in the UTM coordinate system, zone 16, NAD-83.

4.4 Urban versus Rural Dispersion Options

Classification of land use in the immediate area surrounding a facility is important in determining the appropriate dispersion coefficients to select for a particular modeling application. The selection of either rural or urban dispersion coefficients for a specific application should follow one of two procedures. These include a land use classification procedure or a population-based procedure to determine whether the area is primarily urban or rural.[26]

Of the two methods, the land use procedure is considered more definitive. The land use within the total area circumscribed by a 3-km radius circle around the facility was classified using the land use typing scheme proposed by Auer. If land use types 23 (Developed, Medium Intensity), or 24 (Developed, High Intensity) account for 50% or more of the circumscribed area, urban dispersion coefficients should be used; otherwise, rural dispersion coefficients are appropriate.

AERSURFACE (v20060) was used for the extraction of the land-use values in the domain. The results of the land use analysis evaluation were as follows.

Each USGS National Land Cover Database (NLCD) 2016 land use class was compared to the most appropriate Auer land use category to quantify the total urban and rural area. Table 4-1 summarizes the results of this land use analysis. As approximately 99.4% of the area can be classified as rural, the use of rural dispersion coefficients is justified.

Table 4-1. Summary of Land Use Analysis

Category ID	Category Description	Number of Grid Cells	Percent	Dispersion Class
11	Open Water	118	0.4%	Rural
21	Developed, Open Space	938	3.0%	Rural
22	Developed, Low Intensity	244	0.8%	Rural
23	Developed, Medium Intensity	70	0.2%	Urban
24	Developed, High Intensity	103	0.3%	Urban
31	Barren Land	24	0.1%	Rural
41	Deciduous Forest	5,811	18.5%	Rural
42	Evergreen Forest	14,600	46.5%	Rural
43	Mixed Forest	2,079	6.6%	Rural
52	Shrub/Scrub	2,852	9.1%	Rural
71	Grassland/Herbaceous	3,178	10.1%	Rural
81	Pasture/Hay	869	2.8%	Rural
82	Cultivated Crops	0	0.0%	Rural
90	Woody Wetlands	537	1.7%	Rural
95	Emergent Herbaceous Wetlands	6	0.0%	Rural
	Total	31,429	100%	
	Urban		0.6%	
	Rural		99.4%	

Therefore, AERMOD was evaluated considering rural dispersion coefficients.

[26] 40 CFR Part 51, Appendix W, the Guideline on Air Quality Models (January 2017) – Section 7.2.1.1(b)(i)

4.5 Meteorological Data

Site-specific dispersion models require a sequential hourly record of dispersion meteorology representative of the region within which the source is located. In the absence of site-specific measurements, the EPA guidelines recommend the use of readily available data from the closest and most representative National Weather Service (NWS) station. Regulatory air dispersion modeling using AERMOD requires five years of quality-assured meteorological data that includes hourly records of the following parameters:

- Wind speed;
- Wind direction;
- Air temperature;
- Micrometeorological parameters (e.g., friction velocity, Monin-Obukhov length);
- Mechanical mixing height; and
- Convective mixing height.

The first three of these parameters are directly measured by monitoring equipment located at typical surface observation stations. The friction velocity, Monin-Obukhov length, and mixing heights are derived from characteristic micrometeorological parameters and from observed and correlated values of cloud cover, solar insulation, time of day and year, and latitude of the surface observation station. Surface observation stations form a relatively dense network, are almost always found at airports, and are typically operated by the NWS. Upper air stations are fewer in number than surface observing points since the upper atmosphere is less vulnerable to local effects caused by terrain or other land influences and is therefore less variable. The NWS operates virtually all available upper air measurement stations in the United States.

The *Guideline* states in Section 8.4.2(e), "Meteorological Input Data – Recommendations and Requirements" that:

> *The use of 5 years of adequately representative NWS or comparable meteorological data, at least 1 year of site-specific, or at least 3 years of prognostic meteorological data, are required.*

The meteorological data that are "representative" for a particular facility may be determined using qualitative and quantitative procedures, and the Guideline offers the following guidance in Section 8.4.1(b).

> *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 Talbot County, Georgia. EPD has provided the most recent five years of meteorological data on their website.[27] Assignment of station pairings to each county was based on distance

[27] 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.

to the centroid of the county, climatological zone, data collection period, and data completeness criteria. For Talbot County, the Georgia EPD provides surface data from the Columbus Metropolitan Airport, and upper air data from Peachtree City/Falcon Field. The Columbus Metropolitan Airport meteorological station is located at 32.516 degrees (latitude) and -84.942 degrees (longitude) and is approximately 25 km Southwest of the facility. Meteorological data sets provided by the Georgia EPD covered the time period from 2017 to 2021, and include meteorological data processed both with and without the ADJ_U* option of AERMET. The 2017 to 2021 meteorological data set with the ADJ_U* option, was utilized for this modeling analysis. A representativeness evaluation comparing the surface characteristics around the facility's location, and the project site, are included as part of this application.

A comparison of the surface characteristics of both the site and the Columbus, Georgia surface station (KCSG), using data output from AERSURFACE (v20060) is shown below in Table 4-2. Results are generally comparable for various parameters (e.g., albedo values) and as such show that the meteorological data set is representative of the proposed project site.

Table 4-2. Comparison of Site and Airport Surface Characteristics

	Albedo								Albedo			
	Columbus 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	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.15	-13%	-7%	-7%	-7%

	Bowen Ratio								Bowen Ratio			
	Columbus 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	0.99	0.77	0.74	0.99	0.86	0.61	0.38	0.86	-15%	-26%	-95%	-15%
Dry	2.36	1.93	1.82	2.36	1.69	1.36	0.81	1.69	-40%	-42%	-125%	-40%
Wet	0.58	0.52	0.52	0.58	0.38	0.31	0.25	0.38	-53%	-68%	-108%	-53%

	Surface Roughness Length (m)								Surface Roughness Length (m)			
	Columbus 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	0.156	0.191	0.221	0.199	0.577	0.609	0.631	0.623	73%	69%	65%	68%
30 - 60	0.152	0.178	0.199	0.179	0.614	0.724	0.793	0.784	75%	75%	75%	77%
60 - 90	0.079	0.101	0.129	0.112	0.176	0.285	0.352	0.349	55%	65%	63%	68%
90 - 120	0.213	0.260	0.305	0.280	0.227	0.341	0.410	0.408	6%	24%	26%	31%
120 - 150	0.173	0.217	0.256	0.231	0.417	0.540	0.613	0.606	59%	60%	58%	62%
150 - 180	0.205	0.246	0.280	0.257	0.451	0.516	0.664	0.657	55%	52%	58%	61%
180 - 210	0.141	0.165	0.184	0.165	0.394	0.505	0.678	0.671	64%	67%	73%	75%
210 - 240	0.150	0.175	0.195	0.176	0.522	0.599	0.736	0.723	71%	71%	74%	76%
240 - 270	0.145	0.169	0.189	0.169	0.438	0.544	0.604	0.595	67%	69%	69%	72%
270 - 300	0.259	0.286	0.307	0.286	0.287	0.422	0.503	0.497	10%	32%	39%	42%
300 - 330	0.146	0.175	0.200	0.179	0.384	0.430	0.458	0.450	62%	59%	56%	60%
330 - 360	0.130	0.162	0.191	0.170	0.323	0.394	0.435	0.427	60%	58.9%	56%	60%
Average	0.162	0.194	0.221	0.200	0.401	0.492	0.573	0.566	59%	61%	61%	65%

4.6 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 were built into the model and downwash influences were evaluated appropriately.

4.7 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.[28] None of the facility's emission unit stacks exceed GEP height.

[28] 40 CFR §51.100(ii)

4.8 Modeled Emission Sources

As discussed in Section 3 of this report, the Significance Analysis evaluates the calculated emission increases associated with the specific project and does not take into consideration any regional off-site emissions sources or other facility emission sources that will not experience an increase in emissions associated with the project (i.e., only Turbines T1-T4 are considered in the Significance Analysis). The NAAQS analysis considers emissions from both on-site and off-site sources. This section discusses the emission sources considered, emission rates, and modeling methods utilized in the Significance Analysis and NAAQS analysis.

4.8.1 Representation of Emission Sources

OPC modeled the project-associated sources for the Significance Analysis. This includes emissions increases from the Turbines T1-T4. This analysis does not include the three natural gas fired fuel oil heaters or Turbines T5-T6, since the fuel gas heaters are not part of the project (do not operate for fuel oil combustion), and Turbines T5-T6 are not being modified or otherwise altered as part of this project.

Parameters selected for natural gas and fuel oil operation for the Significance Analysis were based on results of a variable load analysis, discussed in detail below. The worst-case scenario for each pollutant and averaging period was carried forward to the subsequent significance runs.

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. Past actual short-term emissions were based on operation for short-term periods (e.g., lb/hr for the time period operated, so amount of emissions divided by the amount of time operated). For modeling past actual emissions for long-term (annual) averaging periods, an annualized short-term (lb/hr) emission rate to use in the model was determined based on actual annual emissions divided by the total number of hours the units could have potentially operated. For periods of natural gas firing, the modeled emission rates were based on the worst-case load emission rate, described in detail in Section 4.8.3. For periods of fuel oil firing, the modeled emission rates were based on future potential emissions as a positive emission rate and past actuals as a negative emission rate.[29] In addition, the Significance runs included an additional series assessing the modeled impacts of emissions from periods of startup and shutdown scenarios for 1-hr and 8-hr CO as well as 1-hr and annual NO_2. Since the 1-hr NO_2 Significance Analysis exceeded the Class II SILs, a NAAQS analysis incorporating nearby sources was required (cumulative impact analysis) as discussed below.

For the cumulative impact analysis, all sources at the facility (with the exception of the emergency fire pump engine and fuel oil tanks) and the appropriate regional inventory sources were included at their potential emission rates.

OPC emissions sources modeled for the 1-hr NO_2 NAAQS analysis included the facility's four simple cycle combustion turbine systems (T1-T4) being modified, Turbines T5-T6, and the three natural gas heaters (H1-H3). The natural gas heaters were conservatively included in the 1-hr NO_2 NAAQS evaluations for both periods of natural gas-firing and fuel oil-firing in the combustion turbines. As outlined in Section 4.8.3,

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[29] 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 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 were utilized in the dispersion model for NO_2 modeling.

modeling for this project considered operations at the worst-case load (as the normal site operating condition), and an additional series of assessments for emissions from startup and shutdown scenarios for the 1-hr NO_2 NAAQS.

4.8.2 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, and the only pollutants for which short term (e.g., 1-hr) averaging periods exist. 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 the combustion turbines, and represent atmospheric conditions for both overnight and daylight conditions for startup and shutdown activities. 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 typically involve a limited number of turbines starting simultaneously.
- A cold startup cycle (approximately 1 hour) was the focus of the SUSD modeling, as it is the worst-case SUSD condition based on the emissions and duration of startup. Startup and shutdown periods were estimated to occur for one hour per event, based on vendor-provided data, and emissions were calculated using vendor-provided emissions data and a maximum of 227 startup/shutdown cycles per unit per year on natural gas and 27 startup/shutdown cycles per unit per year on fuel oil (based on a permit limit of 254 startup/shutdown cycles per year total per unit). [30]
- All operating hours outside of SUSD the turbines were conservatively assumed to be at normal operation at the worst-case load for each turbine.
- Startup source parameters (velocity/temperature/emissions) were developed for each hour of the startup cycle based on data provided by OPC.

4.8.3 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 70% load is not necessarily "70% of the 100% 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 decreases correspondingly, which can lead to reduced expected impacts to ambient air quality relative to the 100% load scenario.

[30] For clarification, both startup and shutdown events are sub-hourly events. Since the minimum time step of the AERMOD model is 1 hour, an input of hourly data is required. Data was provided by the vendor which included total emissions for the hour (inclusive of both the startup or shutdown period for the hour, with the remainder of the hour being normal source operation), and weighted averaged temperature and flow/velocity information necessary for inputting data in the model as a startup or shutdown "hour". A cold startup was chosen as the focus of the startup/shutdown modeling as it is the worst case conditions based on larger magnitude of emissions and duration of startup. Similarly, a worst case shutdown condition (shutdown "ending" an hour) was chosen based on larger magnitude of emissions and duration of the shutdown.

What is most important to remember, is that the simple cycle combustion turbine units at the facility are designed to operate for continuous periods only at high loads (70% load or higher).[31]

The source parameters for the simple cycle units (T1-T4) when operating at 70% load, 80% 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 70% load basis was the overall worst-case modeling condition for most operating conditions for both fuel types. However, there were pollutants and averaging periods that had worst-case loads at 80% or 100%. The worst-case load condition was carried through as the normal operating condition for the associated pollutant, averaging period, and fuel type in all modeling assessments for the project, including SIL, NAAQS, and PSD Increment evaluations.

Source parameters for the 100%, 80%, and 70% load conditions, utilized in the modeling assessment, are included in Appendix D.

4.8.4 Significance Analysis

The Significance Analysis was conducted to determine whether the emissions increases associated with the proposed project are modeled to exceed the SIL. This analysis is based on modeling only the emissions from new, modified, or associated sources comprising the project; no existing unmodified or associated sources are included, nor are sources from other regional facilities. For this project, significance modeling included Turbines T1-T4 (as modified units).

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 Turbines 1-4 were derived and carried through the analyses for NO_2, PM_{10}, and $PM_{2.5}$.
- 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 for fuel oil, 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 CO, PM_{10} and $PM_{2.5}$ Significance Analyses for natural gas, the worst-case load emissions were utilized. The future potentials (worst-case load) were selected for the natural gas significance runs.
- 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 4.8.5), 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 significance for NO_2.
- Past actual emissions (based on the last 2 years data, unless otherwise noted) were derived through:

[31] Per data provided by the vendor (Siemens), the minimum emissions compliance load is 70%. Normal source operation will not include long periods of operation at loads below 70%, except during transient conditions. Therefore, no load analyses below 70% were conducted.

- For NO_2 and CO 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.

- 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.

4.8.5 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. OPC has utilized ARM2, in regulatory default mode, 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.

4.8.6 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, and an estimation of secondary $PM_{2.5}$ impacts for Class I SIL analyses.

4.8.6.1 Ozone MERPS Assessment

All MERP data was pulled from the EPA MERPs View Qlik database.[32] The selected MERP values (tpy) for the project are 250 tpy NO_X and 60,114 tpy VOC. These values were representative of data available from the Coffee County, Georgia hypothetical source site. There are only two hypothetical source sites in Georgia: a location in Coffee County and a location in Fulton County. The Coffee County site location is in a more rural area similar to the setting and location of the facility and was therefore chosen as a more representative hypothetical source location. When available, the 90 meter stack data was utilized from Qlik. While the stack for the facility combustion turbine units is not as tall as 90 meters, given the very high exhaust flow

[32] https://www.epa.gov/scram/merps-view-qlik

and temperature from the stacks, their effective stack height and plume rise are significant and more attuned to a taller stack.

Per Equation 2 of the EPD guidance, the SIL analysis demonstration for the proposed project is as follows:

(554.16 tpy NO_X project emissions increase / 250 tpy NO_X 8-hr O_3 MERP) + (44.97 tpy VOC project emissions increase / 60,114 tpy VOC 8-hr O_3 MERP) = 2.21 + 0.001 = 2.22

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:

$$Background\_ozone \text{ (58 ppb) } + 2.22 \text{ x } SIL\_ozone \text{ (1 ppb) } = 60.22 \text{ ppb}$$

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.

4.8.6.2 $PM_{2.5}$ MERPS Assessment – Class II SILs Analysis

As mentioned above, all MERP data was pulled from the EPA View Qlik database. The selected MERP values for this evaluation are 5,851 tpy NO_X, and 1,472 tpy SO_2 for daily $PM_{2.5}$, and 21,697 tpy NO_X and 7,148 tpy SO_2 for annual $PM_{2.5}$. There are only two hypothetical source sites in Georgia: a location in Coffee County and a location in Fulton County. The Coffee County site location is in a more rural area similar to the setting and location of the facility and was therefore chosen as a more representative hypothetical source location. When available, the 90 meter stack data was utilized from Qlik. While the stack for the facility combustion turbine units is not as tall as 90 meters, given the very high exhaust flow and temperature from the stacks, their effective stack height and plume rise are significant and more attuned to a taller stack.

Per Example 1 of the EPD guidance, the SILs analysis demonstration is as follows:

For annual $PM_{2.5}$:

(554.16 tpy NO_X project emissions increase / 21,697 tpy NO_X Annual MERP) + (5.9 tpy SO_2 project emissions increase / 7,148 tpy SO_2 Annual MERP) = 0.0264, or 2.64%

This effectively means, that so long as direct modeled impacts of annual $PM_{2.5}$ are less than 97.36% 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 0.00527 μg/m^3 (2.64% of 0.2 μg/m^3) that could be applied to modeling for $PM_{2.5}$, for the annual averaging period.

For daily $PM_{2.5}$:

(554.16 tpy NO_X project emissions increase / 5,851 tpy NO_X Daily MERP) + (5.9 tpy SO_2 project emissions increase/1,472 tpy SO_2 Daily MERP) = 0.0987 or 9.87%

This effectively means, that so long as direct modeled impacts of daily $PM_{2.5}$ are less than 90.13% 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 0.11846 μg/m^3 (9.87% of 1.2 μg/m^3) that could be applied to modeling for $PM_{2.5}$, for the daily averaging period.

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 the facility, where modeled primary $PM_{2.5}$ impacts are at their highest.

Secondary $PM_{2.5}$ has been added into the summary tables for all $PM_{2.5}$ Class II modeling results in Section 5 and added to modeled results. Although not directly evaluated in Section 5 in the summary tables, secondary $PM_{2.5}$ was also considered for PM_{10} significance results, and the small contributions from secondary $PM_{2.5}$ would have no influence on the findings of the PM_{10} significance analyses summarized in Section 5.

4.8.6.3 $PM_{2.5}$ 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 NO_X and SO_2 emissions was considered. A representative source was chosen as the Coffee County, Georgia hypothetical source from the EPA MERPSs View Qlik website (https://www.epa.gov/scram/merps-view-qlik) based on the similar topography/climate and rural setting as the facility. Data was extracted from Qlik for the approximate distance to the closest Class I area 50-km ring utilized in the analysis (40 km), and data for the 1,000 tpy source with a 90 meter tall stack was chosen. While the stack for the facility combustion turbine units is not as tall as 90 meters, given the very high exhaust flow and temperature from the stacks, their effective stack height and plume rise are significant and more attuned to a taller stack. The project emissions were then used to scale the indicated concentrations at that distance (40 km) to derive an annual secondary $PM_{2.5}$ MERP contribution of 2.36E-03 μg/m^3 and 9.06E-02 μg/m^3 contribution for the daily averaging period.

The following table provides a summary of the data utilized in the analysis. A sample calculation for the data found in the table below is as follows:

NOx Daily MERP Contribution = (554.16 project emissions / 1,000 tpy modeled source) * (0.154919013 μg/m^3 hypothetical source result) = 8.58E-02 μg/m^3

Table 4-3. Class I SIL Modeling MERPs Contribution

Parameters	Project Emission Increase NOx (tpy)	NOx MERP Contribution Values Daily $PM_{2.5}$	NOx MERP Contribution Values Annual $PM_{2.5}$	Project Emission Increase SO_2 (tpy)	SO_2 MERP Contribution Values Daily $PM_{2.5}$	SO_2 MERP Contribution Values Annual $PM_{2.5}$	Units
Project Emissions	554.16	1,000		5.90	1,000		(tpy)
Hypothetical Source Modeled Concentration		0.154919013	0.00409957		0.802650034	0.015733196	(μg/m^3)
MERP Contribution (μg/m^3)		8.58E-02	2.27E-03		4.74E-03	9.28E-05	(μg/m^3)
					Total Daily MERP Contribution	9.06E-02	(μg/m^3)
					Total Annual MERP Contribution	2.36E-03	(μg/m^3)

Note: Concentration values specific to distance of 40 km from the source.

4.8.7 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), or if there are significant emissions from a project located at a greater distance. None of the Class I areas are within 50 km of the facility. 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 project increases, due to the large distance to the nearest Class I areas.[33]

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[33] 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 4.8.3, a load analysis evaluating modeled impacts at 100%, 80%, and 70% load for Turbines 1-4 for both natural gas and fuel oil was conducted. The results of that analysis are shown in Table 5-1 and Table 5-2.

Table 5-1. Turbine Load Analysis – Natural Gas

Pollutant	Averaging Period	5-Year Average?[1]	Modeled Output	Load Analysis Modeled Conc. (µg/m^3)[2]		
				100%	80%	70%
CO	1-hour	No	H1H	6.28586	7.90826	**9.12033**
	8-hour	No	H1H	3.08600	4.24872	**4.96050**
NO_2	1-hour	Yes	H1H	8.94047	14.24618	**15.27199**
	Annual	No	H1H	0.19998	**0.20035**	0.19899
PM_{10}	24-hour	No	H1H	0.93763	1.31603	**1.48877**
	Annual	No	H1H	**0.06796**	0.06789	0.06740
$PM_{2.5}$	24-hour	Yes	H1H	0.73491	0.77264	**0.77794**
	Annual	Yes	H1H	0.05882	**0.05912**	0.05882

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 tuebine has the same emission rates for PM_{10} and $PM_{2.5}$ and with individual years of meterological data.

Table 5-2. Turbine Load Analysis – Fuel Oil

Pollutant	Averaging Period	5-Year Average	Modeled Output	Load Analysis Modeled Conc. (µg/m^3)[2]		
				100%	80%	70%
CO	1-hour	No	H1H	13.50292	**17.56151**	17.27463
	8-hour	No	H1H	6.61358	9.28964	**9.97696**
NO_2	1-hour	Yes	H1H	36.70302	58.33900	**59.04963**
	Annual	No	H1H	0.80933	**0.81510**	0.80997
PM_{10}	24-hour	No	H1H	1.24141	1.78516	**1.88917**
	Annual	No	H1H	0.09089	**0.09154**	0.09122
$PM_{2.5}$	24-hour	Yes	H1H	0.99162	1.01881	**1.05042**
	Annual	Yes	H1H	0.07860	**0.07969**	0.07956

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 tuebine has the same emission rates for PM_{10} and $PM_{2.5}$ and

Based on the results above, analyses indicate that the 70% load condition was the worst-case modeling condition for a majority of pollutants. However, there were instances of worst-case loads for 80% and 100% operating scenarios. Therefore, the worst-case load condition for the respective pollutant, fuel type, and averaging period was carried forward for all 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 5-3 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 periods of natural gas operation and periods of fuel oil operation for facility's four combustion turbines proposed to be modified under the proposed project are evaluated and summarized in Table 5-3. All modeled results reported for the Significance Analysis correspond to H1H modeled impacts.

As discussed in Section 4.8.2, 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 for CO and 1-hr NO_2 included the following:

- Normal site operations at the worst-case load for the entire day.
- Startup for facility turbine units starting at 4 AM, with a later shutdown event, and normal operation for the remainder of the day. [34]
- Startup for facility turbine units starting at 10 AM, with a later shutdown event, and 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.

[34] As explained in Section 4.8.2., data provdied by the vendor (Siemens) allowed generation of representative modeling data for a startup hour and a shutdown hour in the model. So, for each startup/shutdown scenario indicated above (3 AM and 10 AM), a startup event/hour occurred at the time specified with a shutdown event/hour input into the model at a later point in the day. The remainder of the 22 hours of the day were represented in the model as "normal source operation". This is conservative since if the unit shutdown it would no longer have been operating for a full 24-hr period.

Table 5-3. 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	0.19	0.12	0.31	1.2	No	N/A	0.24	0.12	0.36	1.2	No	N/A
	Annual	Yes	H1H	Normal	0.03	5.27E-03	0.03	0.2	No	N/A	0.03	5.27E-03	0.03	0.2	No	N/A
PM_{10}	24-hour	Yes	H1H	Normal	0.36	--	--	5	No	N/A	0.37	--	--	5	No	N/A
	Annual	No	H1H	Normal	0.03	--	--	1	No	N/A	0.03	--	--	1	No	N/A
CO	1-hour	Yes	H1H	Normal	11.83	--	--	2,000	No	N/A	8.44	--	--	2,000	No	N/A
				4 am Startup	31.95	--	--	2,000	No	N/A	73.50	--	--	2,000	No	N/A
				10 am Startup	118.51	--	--	2,000	No	N/A	213.65	--	--	2,000	No	N/A
	8-hour	Yes	H1H	Normal	6.43	--	--	500	No	N/A	3.81	--	--	500	No	N/A
				4 am Startup	6.45	--	--	500	No	N/A	9.26	--	--	500	No	N/A
				10 am Startup	23.08	--	--	500	No	N/A	43.54	--	--	500	No	N/A
NO_2 [3]	1-hour	Yes	H1H	Normal	4.16	--	--	7.5	No	N/A	48.24	--	--	7.5	Yes	49.8
				4 am Startup	12.58	--	--	7.5	Yes	41.8	48.24	--	--	7.5	Yes	50
				10 am Startup	14.00	--	--	7.5	Yes	9.3	53.79	--	--	7.5	Yes	49.8
	Annual	No	H1H	Normal	0.15	--	--	1	No	N/A	0.14	--	--	1	No	N/A

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 3,750 hours per year, and fuel oil operation is expected for 450 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).

As shown in Table 5-3, all CO, PM_{10}, and $PM_{2.5}$ modeled impacts for the project are less than the applicable Class II SILs. As such, by definition, the project does not cause or contribute to an exceedance of the NAAQS or Class II PSD Increment for CO, PM_{10}, and $PM_{2.5}$. However, the NO_2 modeled impacts for the project exceeded the Class II SIL for the 1-hr averaging period. MERPs contribution to the predicted modeled impact, as derived in the analysis in Section 4.8.6, are considered in Table 5-3. As a result, refined analyses for 1-hr NO_2 are required and are summarized in subsequent sections.

Also, as can be seen from Table 5-3, CO predicted modeled impacts for the project are below the 575 μg/m^3 SMC for the 8-hr averaging period and PM_{10} predicted modeled impacts for the project are below the 10 μg/m^3 SMC for the 24-hr averaging period.

As previously described in Section 4.8.4 and 4.8.5, 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 5-3.

Table 5-4. Class I Significance Results for PM_{10}, $PM_{2.5}$, and NO_2

Pollutant	Averaging Period	5-Year Average	Model Output	Natural Gas Operation[1] Modeled Conc. (μg/m^3)	$PM_{2.5}$ MERP Contribution (μg/m^3)	Total $PM_{2.5}$ Impact (μg/m^3)	SIL (μg/m^3)	Exceeds SIL?	Fuel Oil Operation[1] Modeled Conc. (μg/m^3)	$PM_{2.5}$ MERP Contribution (μg/m^3)	Total $PM_{2.5}$ Impact (μg/m^3)	SIL (μg/m^3)	Exceeds SIL?
$PM_{2.5}$	24-hr	Yes	H1H	0.025	9.06E-02	0.12	0.27	No	0.034	0.09	0.12	0.27	No
	Annual	Yes	H1H	4.30E-03	2.36E-03	6.66E-03	0.05	No	4.16E-03	2.36E-03	6.52E-03	0.05	No
PM_{10}	24-hr	Yes	H1H	0.035	--	--	0.3	No	0.046	--	--	0.3	No
	Annual	No	H1H	4.43E-03	--	--	0.2	No	4.61E-03	--	--	0.2	No
NO_2	Annual	No	H1H	0.021	--	--	0.1	No	0.022	--	--	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 3,750 hours per year, and fuel oil operation is expected for 450 hours per year.

As shown in Table 5-4, 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 4.8.6, are considered in Table 5-4.

5.3 NAAQS Analysis

A NAAQS modeling analysis was conducted for the 1-hr NO_2 NAAQS[35] as it was the only applicable pollutant and averaging period for which the Significance Analysis results exceeded the Class II SIL. As described in Section 4, the NAAQS and Increment analyses utilized the significant receptors (as derived from the Significance Analysis) for use in the refined analysis.

[35] As shown in Table 5-3, 1-hr NO_2 results for the four modified combustion turbines operating on natural gas were above the respective Class II SIL for the 4am and 10am SUSD runs. Additionally, all 1-hr NO_2 results for the four modified combustion turbines operating on fuel oil (normal operation, 4am startup, and 10am startup) were above the respective Class II SILs. Therefore, NAAQs runs were completed for these analyses.

As discussed in Section 4.8.2, 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 worst-case 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 Turbines 1-6, the natural gas heaters (H1-H3), and off-site inventory sources as outlined in Section 3.6 of this report.

Table 5-5. NO_2 NAAQS Analysis Results

Pollutant	Averaging Period	5-Year Average	Model Output	Fuel Type	Scenario	Modeled Conc. (μg/m^3)	Background Conc. (μg/m^3)	Total NO_2 Impact (μg/m^3)	NAAQS (μg/m^3)	Exceeds NAAQS?
NO_2	1-hour	Yes	H8H	Natural Gas	4 am Startup	137.33	30.3	167.63	188	No
					10 am Startup	100.37	30.3	130.67	188	No
				Fuel Oil	Normal	1,540.43	30.3	1,570.73	188	Yes
					4 am Startup	1,540.43	30.3	1,570.73	188	Yes
					10 am Startup	1,540.43	30.3	1,570.73	188	Yes

As shown in Table 5-5, during the model runs for periods of fuel oil operation, modeled exceedances of the 1-hr NO_2 NAAQS were predicted associated with two primary inventory sources. These predicted modeled exceedances of the NAAQS were not found in the model runs for periods of natural gas operation, as significant receptors for those runs were not located in the vicinity of the inventory sources of concern.

The areas of predicted modeled exceedances were also in an area of 250 meter receptor grid spacing. The following procedure was then followed for an evaluation of the predicted modeled exceedances found.

1. An initial (1st evaluation) was conducted of all predicted exceeding receptors (from the 250 meter spaced grid) and evaluated to determine if the Talbot Energy Facility sources were significantly contributing (greater than the 1-hr NO_2 SIL) at any time/space a predicted modeled exceedance was occurring. The MAXDCONT option of the model was used with the THRESH option (NAAQS – background, or 157.7 μg/m^3) to evaluate all potential predicted modeled exceedances. Results were evaluated from the H8H all the way to the H168H (where predicted exceedances ended), and for no exceedance was the Talbot Energy Facility found to significantly contribute to the predicted modeled exceedances. The MAXDCONT output file and spreadsheet analyses for each modeled scenario (Normal, 4AM, 10AM) is provided in Appendix E under the respective results folder for that operating scenario.

2. A secondary (2nd evaluation) was conducted by choosing the receptor of maximum modeled impact (from the 1st evaluation) and creating a new small receptor grid around that maximum impact receptor, with 100 meter spacing out to a distance of 500 meters from that receptor. This was done in order to ensure that maximum predicted modeled impacts were resolved to within an area of 100 meter receptor grid spacing. The same procedure as used above in Item #1 with MAXDCONT was used, in this instance with predicted modeled exceedances spanning from the H8H to the H177H. For no predicted modeled exceedance was the Talbot Energy Facility found to significantly

contribute (impacts greater than the SIL). Maximum modeled impacts were sufficiently resolved to within the area of 100 meter grid spacing. The MAXDCONT output file and spreadsheet analyses for each modeled scenario (Normal, 4AM, 10AM) is provided in Appendix E under the respective results folder for that operating scenario.

5.4 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}, $PM_{2.5}$, and CO) and the NAAQS modeling results for 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 TAP impacts were compared against conservative screening levels provided by the EPA specifically to address potential soil and vegetation impacts.[36]

As shown in Table 5-6, 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.

Table 5-6. Soil and Vegetation Impacts

Pollutant	Averaging Period	Total Concentration[1] (µg/m³)	Vegetation Sensitivity[5] Sensitive (µg/m³)	Intermediate (µg/m³)	Resistant (µg/m³)	Secondary NAAQS (µg/m³)	Minimum Threshold (µg/m³)	Threshold Exceeded?
NO_2[1]	4-Hour	1570.7	3,760	9,400	16,920	N/A	3,760	No
	8-Hour	1413.7	3,760	7,520	15,040	N/A	3,760	No
	1-Month	314.1	-	564	-	N/A	564	No
	Annual	0.15	-	94	-	100	94	No
CO[2]	1-wk	43.5	1,800,000	-	18,000,000	N/A	1,800,000	No
PM_{10}[3]	24-hour	0.37	-	-	-	150	150	No
$PM_{2.5}$[4]	24-hour	0.24	-	-	-	35	35	No
	Annual	0.03	-	-	-	15	15	No

1. Results from the NO_2 (1-hr) NAAQS runs were used for 4-hr data based on a conservative scalar value of 1.0 from 1-hr results. Results for the 8-hr concentrations based on a scalar value of 0.9 to 1-hr impacts (from the EPA AERSCREEN User's Guide). The 1-month results value is based on a monthly scalar value of 0.2 from a Minnesota Pollution Control Agency (MPCA) screening modeling guidance document (https://www.pca.state.mn.us/sites/default/files/aera-disperseguide.pdf). Annual results reported the highest annual value from the annual Significance runs.

2. Maximum 8-hr average CO impact from the Significance Analysis. No 1-week averaging period is available in AERMOD, so the 8-hr results were used as a conservative estimate for the weekly impacts. Given the Significance Analysis impacts were negligible in comparison to the corresponding screening threshold, it can be reasonably concluded that Novelis will not cause or contribute to any deleterious soils or vegetation impacts due to air quality.

3. Maximum 24-hr average PM_{10} impact from the Significance Analysis.

4. Maximum $PM_{2.5}$ 24-hr and Annual average impacts from the Significance Analysis.

5. 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.

[36] U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078), 1981.

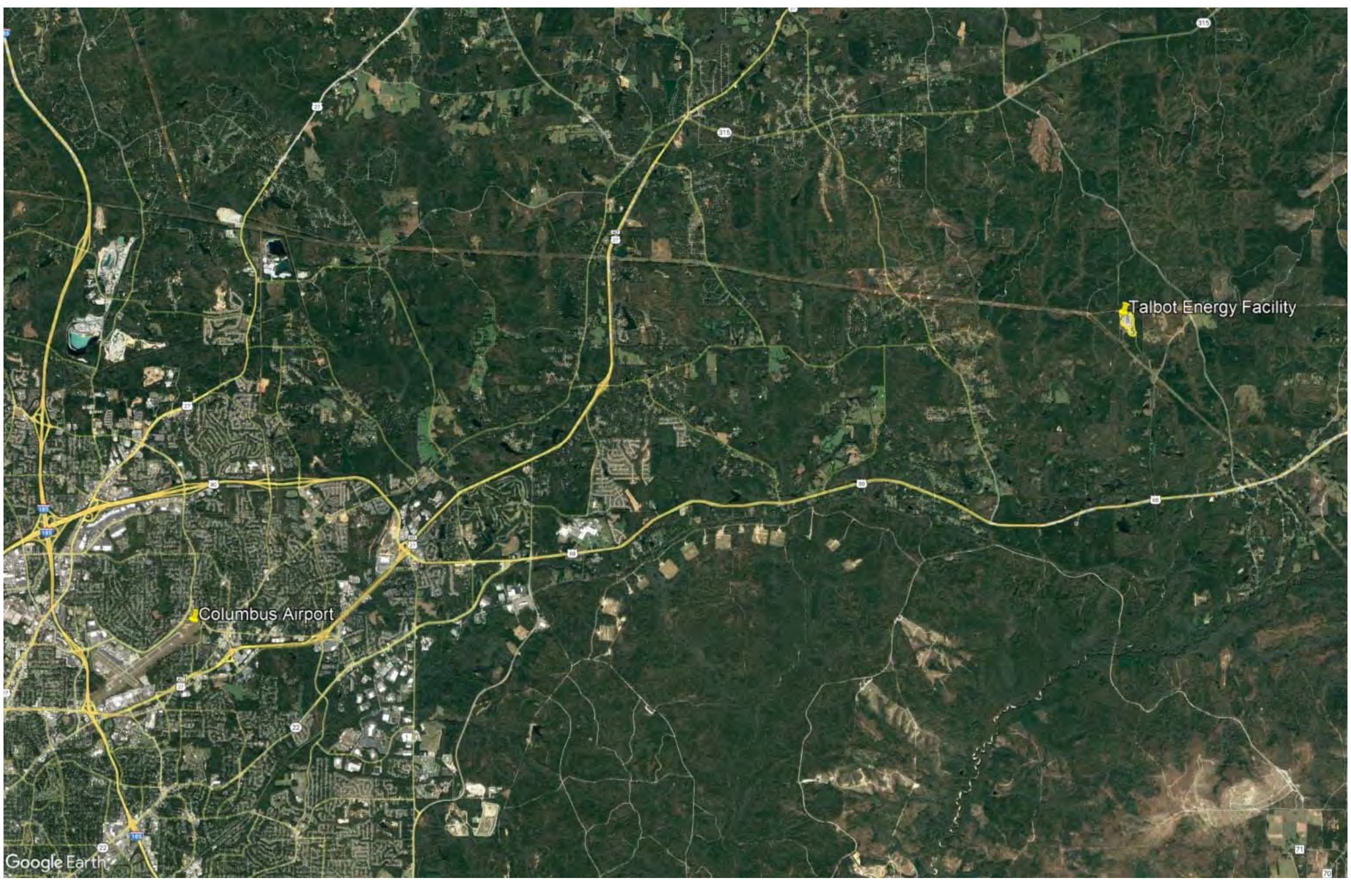
5.5 Class II Visibility Analysis

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 primary sensitive receptor identified within the area of significant impact for 1-hr NO_2 was the Columbus Airport. Therefore, a Class II visibility analysis, utilizing the VISCREEN model, was conducted for the Columbus Airport.

5.5.1 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 facility. 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. OPC determined the closest and primary sensitive receptor in the area was the Columbus airport, located approximately 23 km southwest of the facility. Figure 5-1 below shows the location of the Columbus Airport in relation to the facility.

Figure 5-1. Map of Class II Visibility Areas of Concern Evaluated



5.5.2 VISCREEN Modeling Methodology

The EPA's *Workbook for Plume Visual Impact Screening and Analysis*[37] (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[38] and therefore are used in this analysis. The VISCREEN model output files are provided in Appendix E.

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 area 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.

5.5.3 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 – 233.78 tpy
- NO_X (as NO_2) – 957.97 tpy – conservatively assuming that NO_2 are 90% of NO_X.
- Primary SO_4 – 1.04 tpy – conservatively assumes all sulfuric acid mist is sulfate.

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[37] 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.

[38] New Source Review Workshop Manual (Draft), p. D.6.

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 long periods of 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.

5.5.4 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. OPC used the AERMOD meteorological data files from the other Class II modeling analyses to determine the modeled meteorological conditions using the procedure described in the Workbook.

First, the meteorological data was utilized 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 a small airport would be visibility conditions during daytime hours, the frequency of occurrence of meteorological conditions during the daytime time periods (Hours 7-12, and 13-18) was reviewed. As such, the worst-case meteorological conditions were found to be an E stability, with a 2 m/s wind speed.

A detailed spreadsheet showing how this condition was determined are included as part of the electronic modeling file submittal.

5.5.5 VISCREEN Analysis Results

The results of the Level 2 VISCREEN analysis are summarized in Table 5-7, 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) [39]

[39] 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 5-7. Level 2 VISCREEN Results – Columbus Airport

Background	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10	116	26	53	2.0	0.722	0.05	0.001
SKY	140	116	26	53	2.0	0.216	0.05	-0.004
TERRAIN	10	84	23	84	2.0	0.244	0.05	0.003
TERRAIN	14	84	23	84	2.0	0.057	0.05	0.002

As shown above, the Level 2 VISCREEN results indicate that the proposed project will not cause any significant visible plume impacts at the Columbus Airport. The electronic output and summary files from the VISCREEN runs are included as part of the electronic modeling file submittal (Appendix E).

5.6 Toxic Impact Assessment

Procedures governing the EPD's review of TAP emissions as part of air permit reviews are contained in EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (TAP Guideline)*.[40] Appendix A of the Guideline provides the Allowable Ambient Concentration (AAC) and Minimum Emission Rate (MER) for each TAP.

According to the *TAP Guideline*, dispersion modeling should be completed for each TAP having quantifiable emissions above the MER for that pollutant.

Table 5-8 summarizes the facility-wide emission rates for each TAP in comparison to their respective MERs.

[40] *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 5-8. Facility-Wide TAP Emissions and Respective MER

Pollutant	CAS No.	Combustion Turbine Nos. 1 - 6 (T1 - T6) (tpy)	Fuel Heater Nos. 1 - 3 (H1 - H3) (tpy)	Fire Pump (tpy)	Fuel Oil Tank No. 1 (tpy)	Fuel Oil Tank No. 2 (tpy)	Fuel Oil Tank No. 3 (tpy)	Total Potential Emissions (tpy)	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER? (Y/N)
1,3-Butadiene	106990	4.24E-01	--	3.16E-05	--	--	--	0.42	848.02	7.30	Y
Acetaldehyde	75070	5.68E-01	--	6.20E-04	--	--	--	0.57	1.14E+03	1.11E+03	Y
Acrolein	107028	5.12E-01	--	7.48E-05	--	--	--	0.51	1.02E+03	4.87	Y
Benzene	71432	3.75E-01	1.62E-04	7.54E-04	7.51E-04	8.97E-04	8.97E-04	0.38	756.76	31.63	Y
Ethylbenzene	100414	3.01E-01	--	--	1.22E-03	1.46E-03	1.46E-03	0.31	610.86	2.43E+05	N
Formaldehyde	50000	2.00E+00	5.80E-03	9.54E-04	--	--	--	2.01	4.01E+03	267.00	Y
Naphthalene	91203	6.31E-02	4.71E-05	6.86E-05	1.97E-04	2.35E-04	2.35E-04	6.39E-02	127.78	729.99	N
Propylene Oxide	75569	3.77E-01	--	--	--	--	--	0.38	754.73	656.99	Y
Toluene	108883	1.33E+00	2.63E-04	3.31E-04	8.98E-03	1.07E-02	1.07E-02	1.36	2.72E+03	1.22E+06	N
Xylene (Total)	1330207	1.28E+00	--	2.30E-04	2.38E-02	2.85E-02	2.85E-02	1.36	2.72E+03	2.43E+04	N
Arsenic	7440382	7.67E-03	1.55E-05	--	--	--	--	7.68E-03	15.36	5.67E-02	Y
Beryllium	7440417	6.09E-04	9.28E-07	--	--	--	--	6.10E-04	1.22	0.97	Y
Cadmium	7440439	5.61E-03	8.50E-05	--	--	--	--	5.69E-03	11.38	1.35	Y
Chromium	7440473	1.52E-02	1.08E-04	--	--	--	--	1.53E-02	30.68	58.40	N
Chromium (VI)	7440473(VI)	1.54E-04	4.33E-06	--	--	--	--	1.59E-04	0.32	2.02E-02	Y
Lead	7439921	2.60E-02	3.86E-05	--	--	--	--	2.60E-02	52.05	5.84	Y
Manganese	7439965	8.00E-01	2.94E-05	--	--	--	--	0.80	1.60E+03	12.17	Y
Mercury	7439976	1.13E-03	2.01E-05	--	--	--	--	1.15E-03	2.30	73.00	N
Nickel	7440020	3.29E-01	1.62E-04	--	--	--	--	0.33	657.36	38.64	Y
Selenium	7782492	2.34E-02	1.86E-06	--	--	--	--	2.34E-02	46.78	23.36	Y
Hexane	110543	--	1.39E-01	--	1.49E-04	1.78E-04	1.78E-04	0.14	279.27	1.70E+05	N
Cobalt	7440484	--	6.49E-06	--	--	--	--	6.49E-06	1.30E-02	11.68	N

Based on the comparison of TAPs emitted by the facility to the MERs, a direct modeling evaluation for comparison to the AACs was completed for a number of TAP. The modeling assessment was done using the EPA AERMOD model (version 22112) with the turbine's parameters at 70% load. Modeled source parameters for the TAP modeling assessment can be found in Appendix D of this report.

A summary of the TAP modeling results, with use of AERMOD, is provided in the following table. Modeling files for the TAP modeling assessment can be found in Appendix E.

Table 5-9. Summary of TAP Modeling Analysis Results

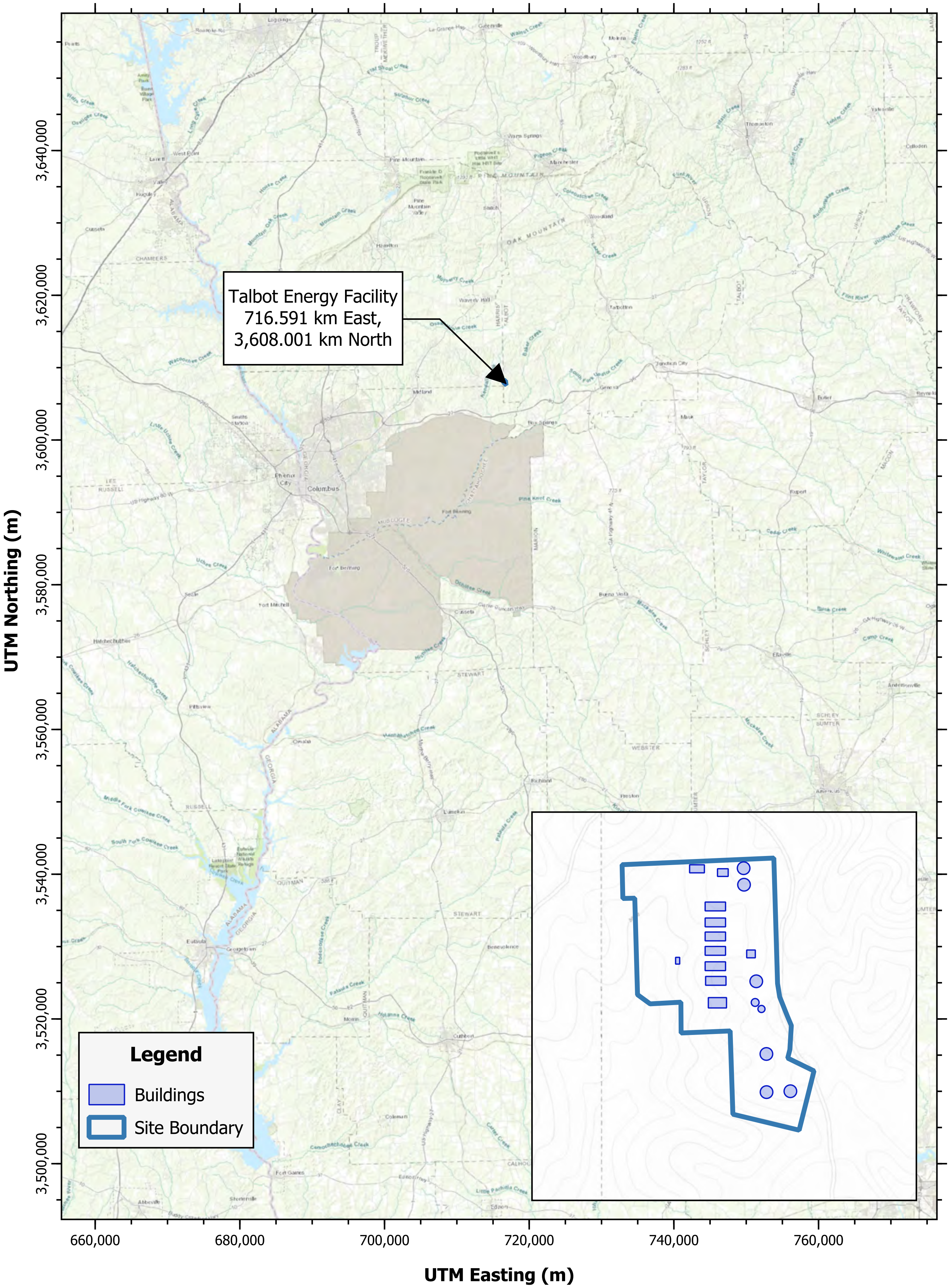
Pollutant	CAS No.	Maximum 1-Hour Impact (μg/m³)	Maximum 15-Min Impact[1] (μg/m³)	15-min AAC[2] (μg/m³)	Is MGLC >15-min AAC? (Y/N)	Maximum 24-hr Impact (μg/m³)	24-hr AAC[2] (μg/m³)	Is MGLC > 24-hr AAC? (Y/N)	Maximum Annual Impact (μg/m³)	Annual AAC[2] (μg/m³)	Is MGLC > Annual AAC? (Y/N)
1,3-Butadiene	106990	1.71E-01	2.26E-01	1.10E+03	N	--	N/A	N/A	2.19E-03	3.00E-02	N
Acetaldehyde	75070	2.79E-02	3.69E-02	4.50E+03	N	--	N/A	N/A	3.50E-04	4.55E+00	N
Acrolein	107028	1.77E-01	2.34E-01	23	N	--	N/A	N/A	2.27E-03	2.00E-02	N
Benzene	71432	9.10E-02	1.20E-01	1.60E+03	N	--	N/A	N/A	2.44E-03	1.30E-01	N
Formaldehyde	50000	1.50E+00	1.98E+00	245	N	--	N/A	N/A	2.86E-02	1.10E+00	N
Propylene Oxide	75569	1.86E-02	2.45E-02	N/A	N/A	--	N/A	N/A	2.30E-04	2.70E+00	N
Arsenic	7440382	4.02E-03	5.31E-03	0	N	--	N/A	N/A	9.00E-05	2.33E-04	N
Beryllium	7440417	2.40E-04	3.17E-04	1	N	--	N/A	N/A	1.00E-05	4.00E-03	N
Cadmium	7440439	2.20E-02	2.90E-02	30	N	--	N/A	N/A	4.10E-04	5.56E-03	N
Chromium (VI)	7440473(VI)	1.12E-03	1.48E-03	10	N	--	N/A	N/A	2.00E-05	8.30E-05	N
Lead	7439921	1.06E-02	1.40E-02	N/A	N/A	2.55E-03	0.1	N	--	N/A	N/A
Manganese	7439965	2.89E-01	3.82E-01	500	N	--	N/A	N/A	3.94E-03	5.00E-02	N
Nickel	7440020	1.19E-01	1.57E-01	N/A	N/A	2.69E-02	0.8	N	--	N/A	N/A
Selenium	7782492	8.46E-03	1.12E-02	N/A	N/A	1.91E-03	0.5	N	--	N/A	N/A

1. 15-minute impacts equal the 1-hour impact times a factor of 1.32 per the Guideline, page 12.
2. Per Appendix A of Georgia EPD Toxics Guidance (Updated October 2018).

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 5-9, the impacts of TAP evaluated from the facility's operations are below all applicable AACs.

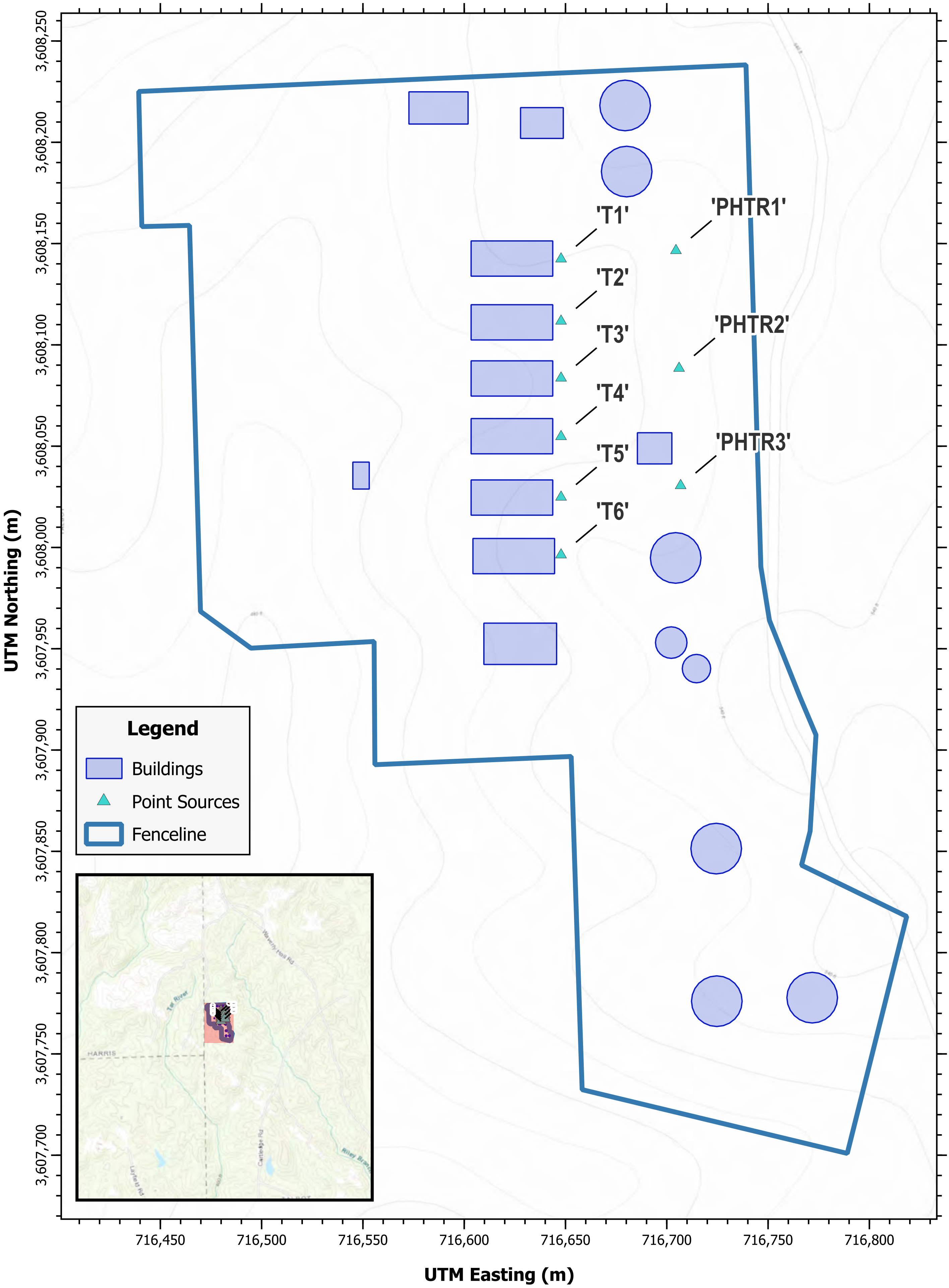
APPENDIX A. FIGURES

Figure A-1. Area Site Map



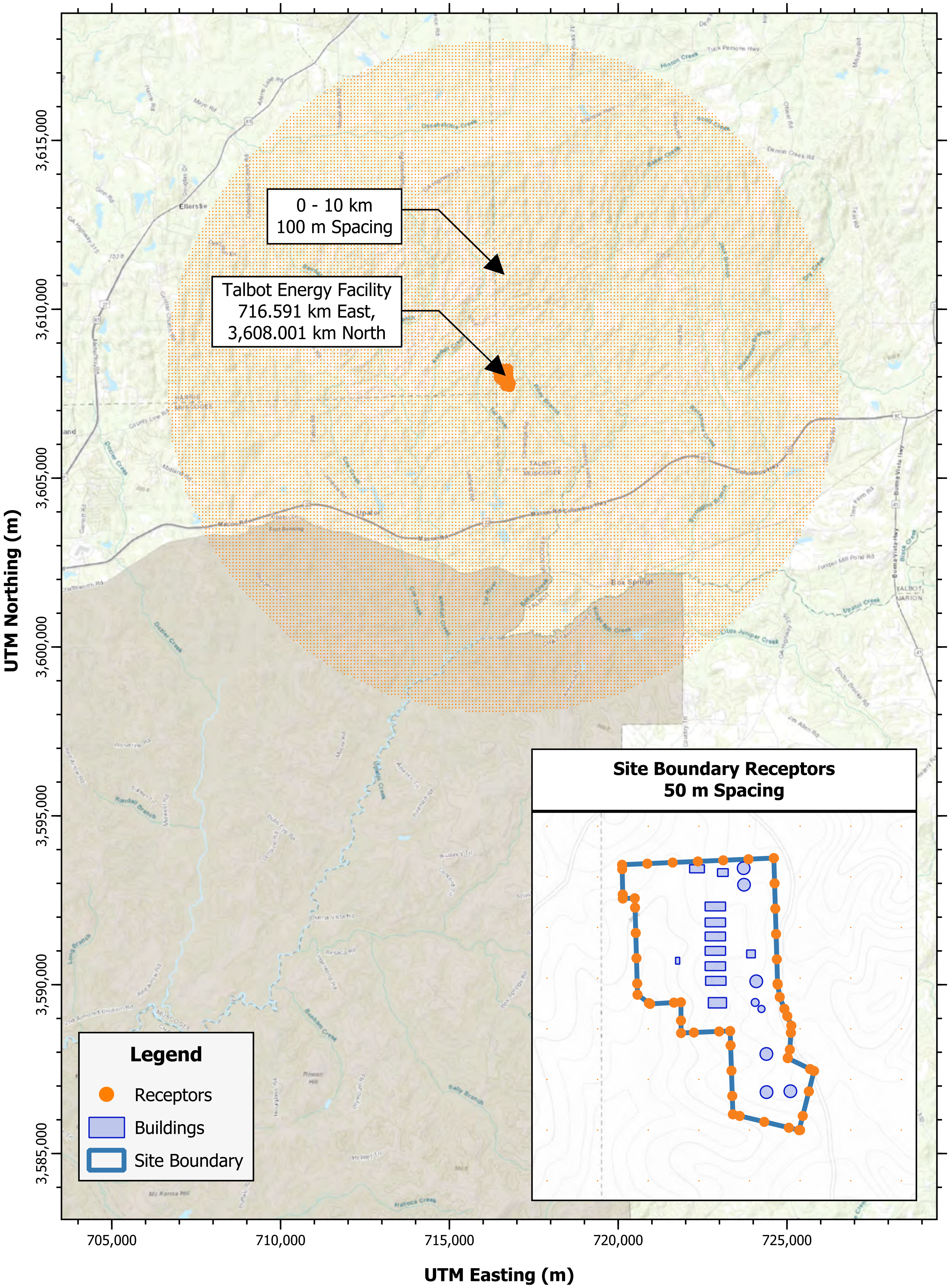
All coordinates shown in UTM Coordinates,
UTM Zone 16, NAD 83 Datum

Figure A-2. Modeled Sources



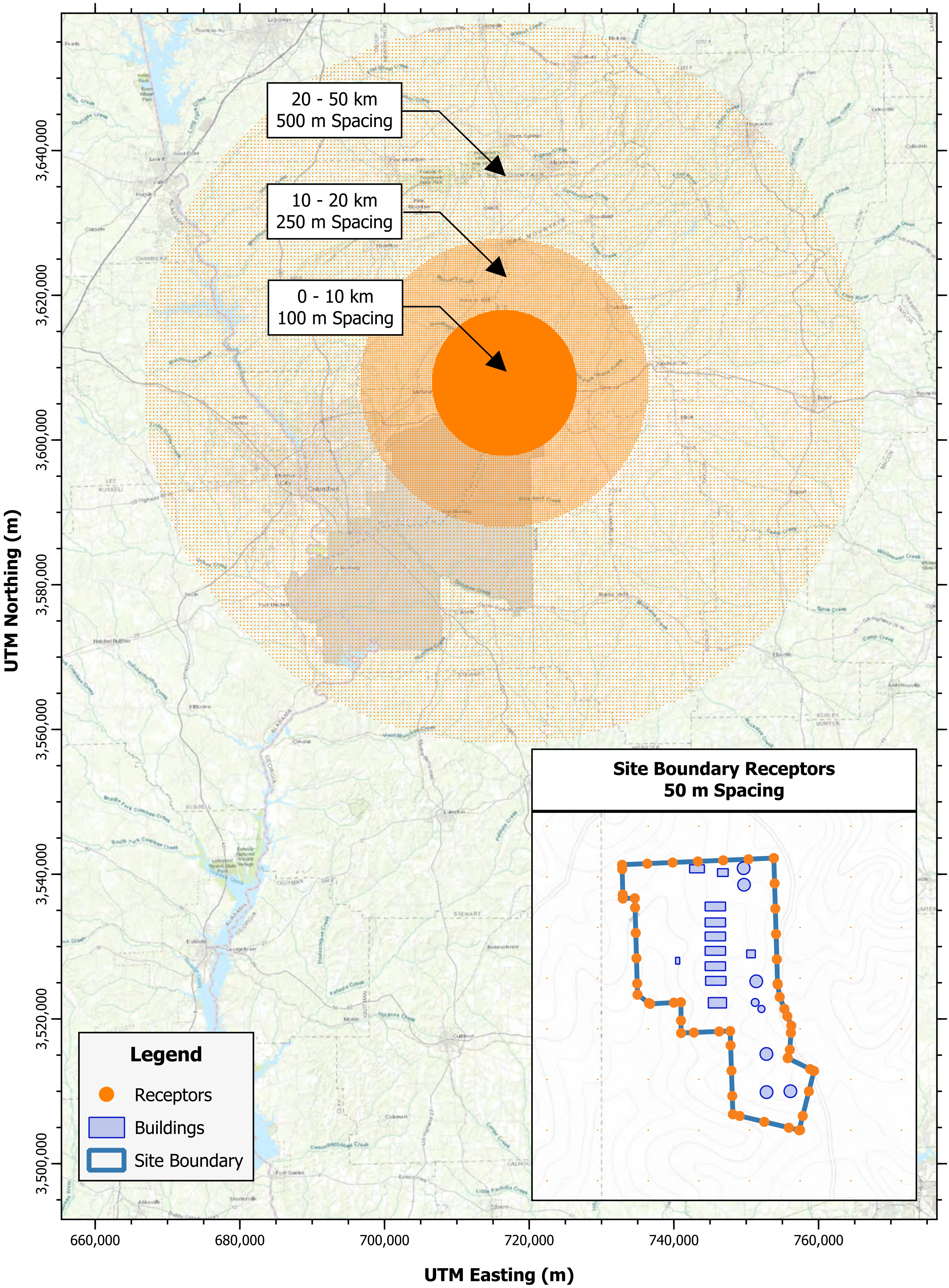
All coordinates shown in UTM Coordinates,
UTM Zone 16, NAD 83 Datum

Figure A-3. 10 km Receptor Grid



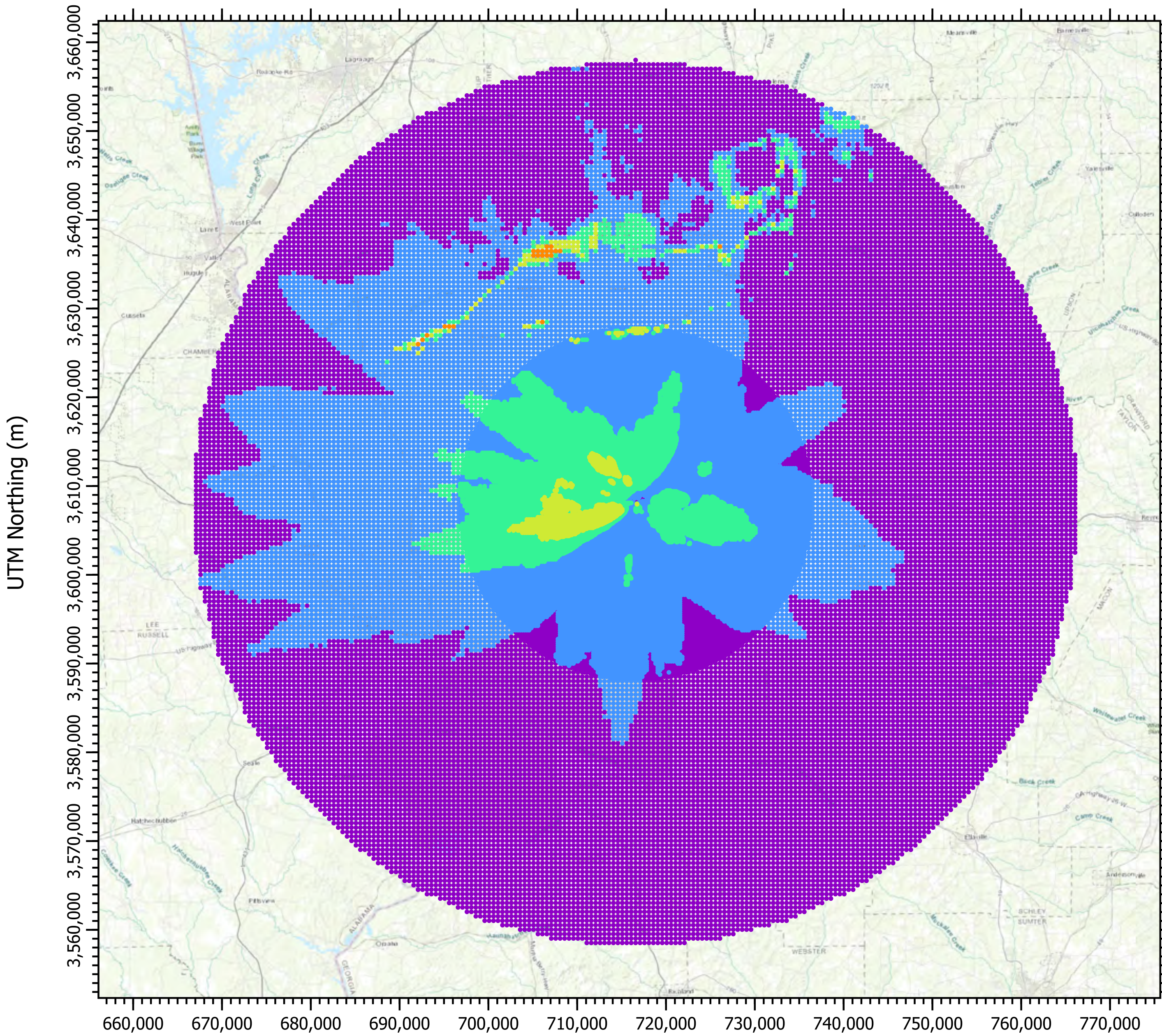
All coordinates shown in UTM Coordinates,
UTM Zone 16, NAD 83 Datum

Figure A-4. 50 km Receptor Grid



All coordinates shown in UTM Coordinates,
UTM Zone 16, NAD 83 Datum

Figure A-5. Natural Gas Combustion - Startup/Shutdown 4 AM: Maximum 1-hr NO_2 Impacts (µg/m³) for SIL Analysis Over Five Meteorological Years Modeled



UTM Easting (m)

All coordinates shown in UTM Coordinates, UTM Zone 16, NAD 83 Datum

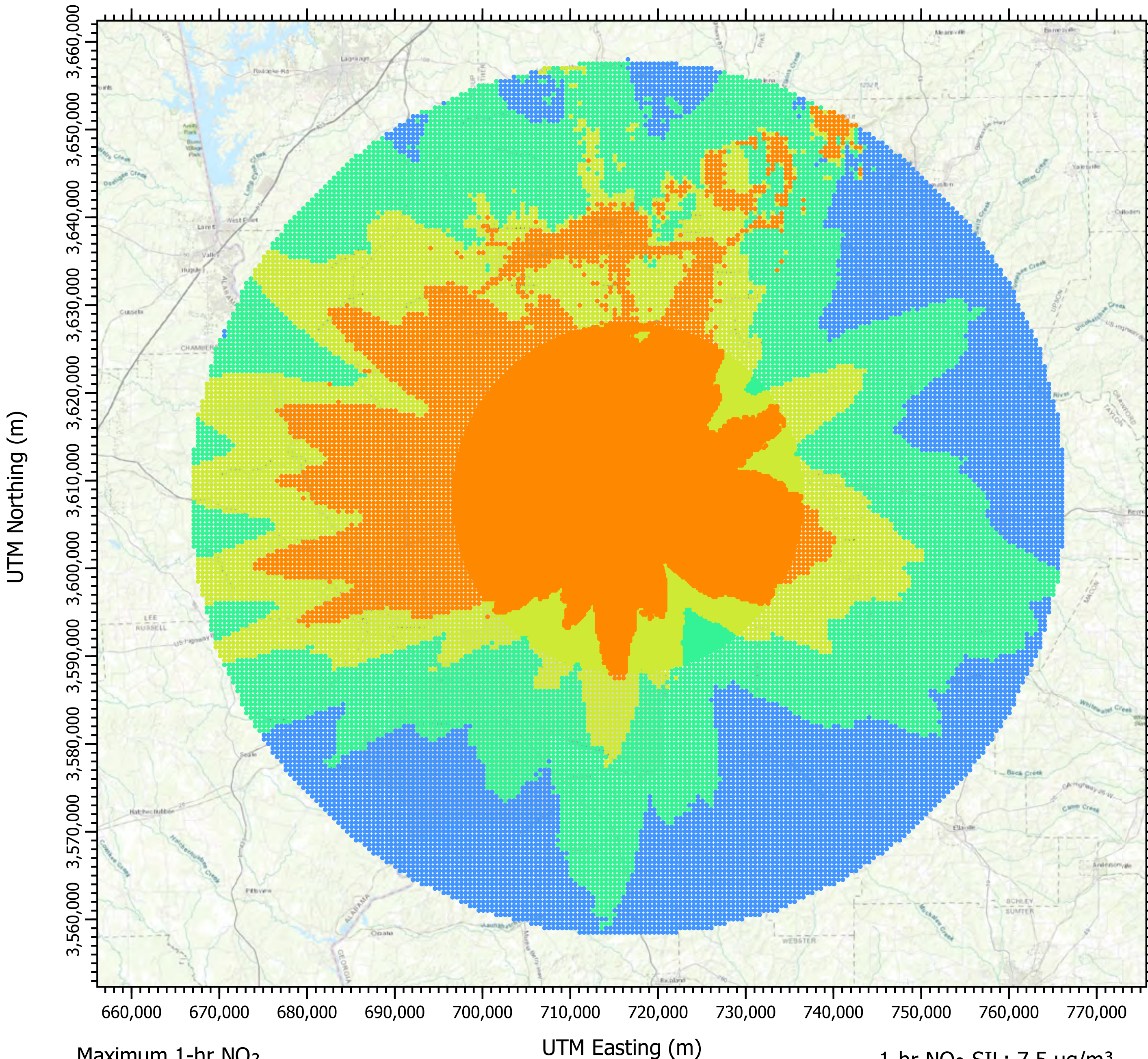
Maximum 1-hr NO_2 concentration (12.6 µg/m³)

1-hr NO_2 SIL: 7.5 µg/m³

NO_2 Concentrations (µg/m³)

- 0.0 - 2.5
- 2.5 - 5.0
- 5.0 - 7.49
- 7.5 - 10.0
- 10.0 - 12.6

Figure A-6. Fuel Oil Combustion - Startup/Shutdown 4AM: Maximum 1-hr NO_2 Impacts (µg/m³) for SIL Analysis Over Five Meteorological Years Modeled



UTM Easting (m)

All coordinates shown in UTM Coordinates, UTM Zone 16, NAD 83 Datum

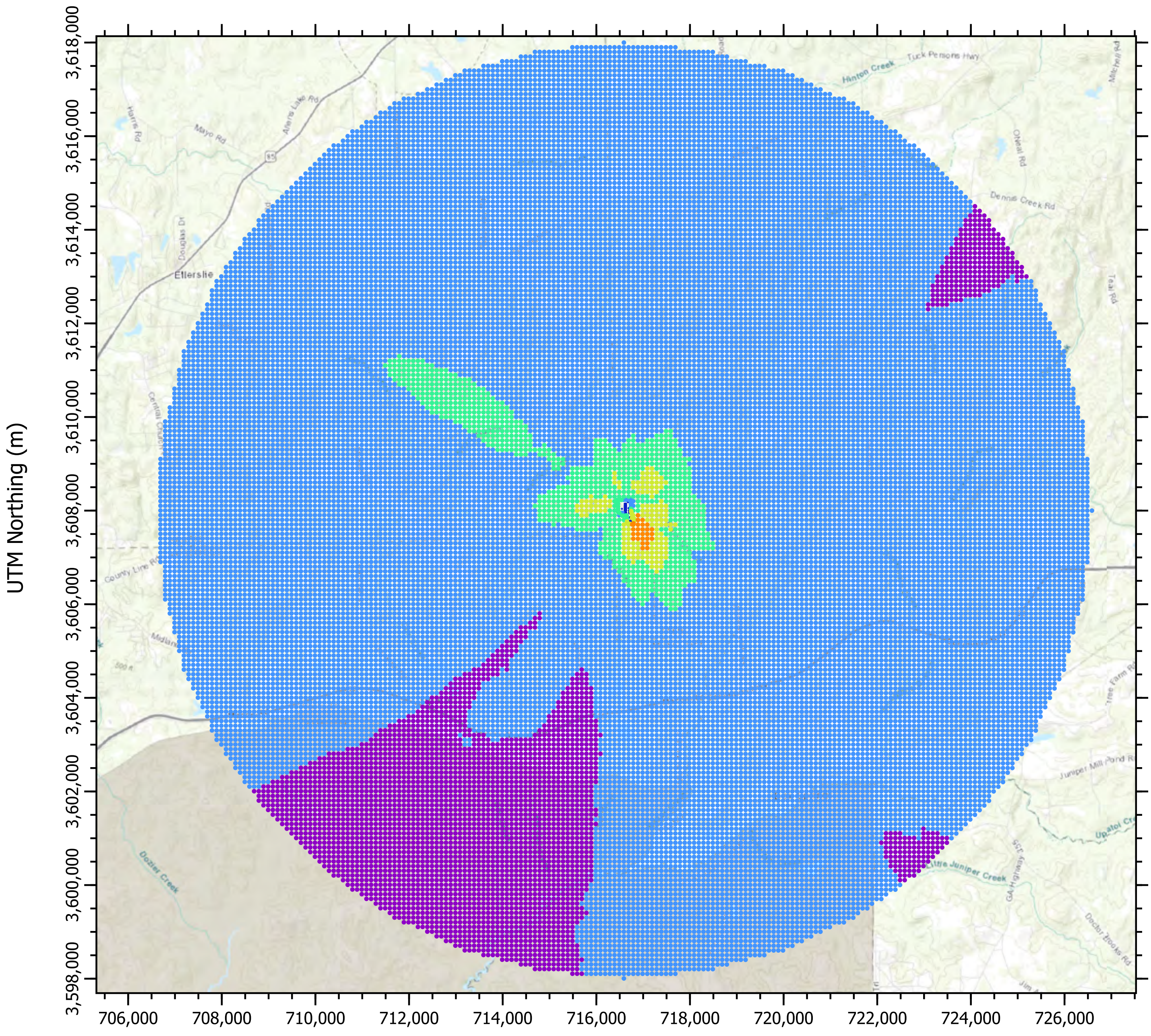
Maximum 1-hr NO_2 concentration (48.3 µg/m³)

1-hr NO_2 SIL: 7.5 µg/m³

NO_2 Concentrations (µg/m³)

- 0.0 - 2.5
- 2.5 - 5.0
- 5.0 - 7.49
- 7.5 - 10.0
- 10.0 - 48.3

Figure A-7. Fuel Oil Combustion: Maximum 24-hr $PM_{2.5}$ Impacts ($\mu g/m^3$) for SIL Analysis Over Five Meteorological Years Modeled



Maximum 1-hr $PM_{2.5}$ concentration (0.36 $\mu g/m^3$)

All coordinates shown in UTM Coordinates, UTM Zone 16, NAD 83 Datum

24-hr $PM_{2.5}$ SIL: 1.2 $\mu g/m^3$

$PM_{2.5}$ Concentrations* ($\mu g/m^3$)

- 0.0 - 0.15
- 0.15 - 0.20
- 0.20 - 0.25
- 0.25 - 0.30
- 0.30 - 0.36

*All values shown include secondary $PM_{2.5}$= 0.118 $\mu g/m^3$

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**

September 1, 2023

Ms. Gisele Majidi-Weese
USDA Forest Service (FS)
Regional Air Program Manager
US Forest Service
1720 Peachtree Rd.
Atlanta, GA 30309

RE: Oglethorpe Power Corporation - Talbot, GA
Fuel Oil Conversion Project
Project in Reference to FS Class I Area

Dear Ms. Majidi-Weese,

Trinity Consultants (Trinity) is submitting this letter to your attention on behalf of our client Oglethorpe Power Corporation (OPC) located in Talbot, Georgia (Talbot County). OPC is proposing to modify four existing simple cycle turbines (Turbines 1-4) to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,750 hr/yr per turbine on natural gas, and 450 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. Additionally, located in Attachment 1 of this letter is the required Request for Determination form outlining the proposed project and Class I area analysis.

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

[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.

corresponding tpy increases. NOx and PM emissions are based on the proposed BACT. SO_2 and H_2SO_4 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 (lb/hr)	FLAG 2010 Approach Annual Emissions[2] (tpy)
NO_X	126.52	554.16
Direct Particulate[1]	24.61	107.81
SO_2	1.35	5.90
H_2SO_4	0.13	0.59
Sum of Emissions (tpy)		1,394.2

1. Direct particulate includes all filterable and condensable PM_{10}.
2. FLAG 2010 Approach: Q = Sum of allowable emissions of project sources * 8760/4200 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the project sources during limited source operation.

The Cohutta Wilderness, and Bradwell Bay 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 - D (km)	Sum of Annualized VAP Emissions - Q (tpy)	Flag 2010 Approach Q/D
Cohutta Wilderness	USFS	249.8	1,394.2	5.58
Bradwell Bay Wilderness	USFS	261.5	1,394.2	5.33

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, or Bradwell Bay Wilderness. Therefore, OPC plans no AQRV analyses for the proposed project. Based on Table 2, OPC 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.
~~~~~~~~~~~~~~~~~~~~~~~~~

OPC 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
Principal Consultant

Attachment 1
Request for Determination Form

Request for Applicability of Class I Area Modeling Analysis
Southern Region, U.S. Forest Service

Facility Name (Company Name)	Oglethorpe Power Corporation
New Facility or Modification?	Modification
Source Type/BART Applicability	PSD Major
Project Location (County/State/ Lat. & Long. in decimal degrees)	Talbot County / GA / 32.588333, -84.692354

Application Contacts

Applicant		***Consultant***		***Air Agency Permit Engineer***	
Company	Oglethorpe Power Corporation	Company	Trinity Consultants, Inc.	Agency	Georgia Environmental Protection Division
Contact	Courtney Adcock	Contact	Justin Fickas	Contact	TBD
Address	2100 East Exchange Place Tucker, GA 30084	Address	1230 Peachtree Street NE, 300 Promenade Atlanta, GA 30309	Address	TBD
Phone #	(770) 270-7678	Phone #	(678) 441-9977	Phone #	TBD
Email	Courtney.adcock@opc.com	Email	jfickas@trinityconsultants.com	Email	TBD

Briefly Describe the Proposed Project

Oglethorpe Power Corporation is modifying four existing turbines at the site (T1-T4) to incorporate the ability to burn natural gas and fuel oil. The project is considered a major modification under PSD permitting requirements.

Proposed Emissions and BACT

Criteria Pollutant	***Emissions***		***Emission Factor (AP-42, Stack Test, Other?)***	***Proposed BACT***
	Maximum hourly (lb/hr)	***Proposed Annual (tons/yr)***		
Nitrogen Oxides	126.52	554.16	Manufacturer Guarantee	12 ppmv at 15% O_2 for Natural Gas (NG) 42 ppmv at 15% O_2 for Fuel Oil (FO)
Sulfur Dioxide	24.61	107.81	40 CFR 75 Appendix D, Equation D-2	0.0006 lb/MMBtu for NG 0.0015 lb/MMBtu for FO
Particulate Matter	1.35	5.90	Manufacturer Guarantee	0.0137 lb/MMBtu for NG 0.023 lb/MMBtu for FO
Sulfuric Acid Mist	0.13	0.59	40 CFR 75 Appendix D, Equation D-2 (10% of SO2 emissions)	0.0004 lb/MMBtu for NG 0.0039 lb/MMBtu for FO

Proximity to U.S. Forest Service Class I Areas

Class I Area	Cohutta Wilderness	Bradwell Bay Wilderness	
Distance from Facility (km)	249.8	261.5	

For Additional Information or Questions, Contact Pleas McNeel
404-638-4813 or pmcneel@fs.fed.us

Trinity Consultants
3495 Piedmont Rd, Bldg 10, Ste 905, Atlanta, GA 30305 / P 678.441.9977 / F 678.441.9978 / **trinityconsultants.com**

September 1, 2023

Mr. Tim Allen
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: Oglethorpe Power Corporation – Talbot, GA
Fuel Oil Conversion Project
Project in Reference to FWS Class I Area – Saint Marks Wilderness and Okefenokee Wilderness

Dear Mr. Allen,

Trinity Consultants (Trinity) is submitting this letter to your attention on behalf of our client Oglethorpe Power Corporation (OPC) located in Talbot, Georgia (Talbot County). OPC is proposing to modify four existing simple cycle turbines (Turbines 1-4) to allow combustion of either natural gas or fuel oil. There is the desire to burn up to 3,750 hr/yr per turbine on natural gas, and 450 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 project 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 (lb/hr)	FLAG 2010 Approach Annual Emissions[2] (tpy)
NO_X	126.52	554.16
Direct Particulate[1]	24.61	107.81
SO_2	1.35	5.90
H_2SO_4	0.13	0.59
Sum of Emissions (tpy)		1,394.2

1. Direct particulate includes all filterable and condensable PM_{10}.
2. FLAG 2010 Approach: Q = Sum of allowable emissions of project sources * 8760/4200 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the project sources during limited source operation.

The Saint Marks Wilderness and Okefenokee 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 - D (km)	Sum of Annualized VAP Emissions - Q (tpy)	Flag 2010 Approach Q/D
Saint Marks Wilderness	USFWS	273.4	1,394.2	5.10
Okefenokee Wilderness	USFWS	277.2	1,394.2	5.03

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 Saint Marks Wilderness, or Okefenokee Wilderness. Therefore, OPC plans no AQRV analyses for the proposed project. Based on Table 2, OPC 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.
~~~~~~~~~~~~~~~~~~~~~~~~~~

OPC 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
Principal Consultant

cc: Catherine Collins; FWS
Jaron E. Ming; FWS

APPENDIX C. MODELING PROTOCOL AND EPD RESPONSE

AIR DISPERSION MODELING PROTOCOL

Talbot Energy Facility / Box Springs, GA

Oglethorpe Power Corporation

Prepared By:

Justin Fickas – Principal Consultant
Tyler Wilcox - Consultant

TRINITY CONSULTANTS
3495 Piedmont Rd, Bldg 10, Ste 905
Atlanta, Georgia 30305
(678) 441-9977

April 2023

Project 221101.0252

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Table 5-2. Comparison of Site and Airport Surface Characteristics 5-6

1. INTRODUCTION

Talbot Energy Facility, owned and operated by Oglethorpe Power Corporation (OPC), is a peaking power plant with six simple cycle combustion turbines (producing a nominal total of 648 megawatts), three fuel gas heaters, and one diesel fuel storage tank. Four of the six combustion turbines (CTs) (Source Codes: T1, T2, T3, and T4) and all three fuel gas heaters (Source Codes: H1, H2, and H3) fire natural gas only. The remaining two CT units (Source Codes: T5 and T6) use natural gas as a primary fuel with the ability to fire distillate fuel oil as a back-up fuel. Dry Low-NO_x (DLN) combustors control NO_x emissions from the turbines, whereas water injection controls NO_x emissions during low sulfur diesel fuel firing of units T5 and T6. Low NO_x burners control NO_x emissions from the fuel gas heaters during gas-fired operation. The facility is proposing to modify four existing simple cycle turbines (Source Codes: T1, T2, T3, and T4) to allow combustion of either natural gas or ultra-low sulfur diesel fuel. As with units T5 and T6, units T1 through T4 will continue to operate primarily on natural gas with fuel oil used as a back-up fuel.

The proposed project will require a Prevention of Significant Deterioration (PSD) permit as a major modification to an existing major source.[1] Project-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]

This dispersion modeling protocol has been prepared following the policy and guidance of the Georgia Environmental Protection Division (GAEPD). Trinity Consultants (Trinity), on behalf of OPC, 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.

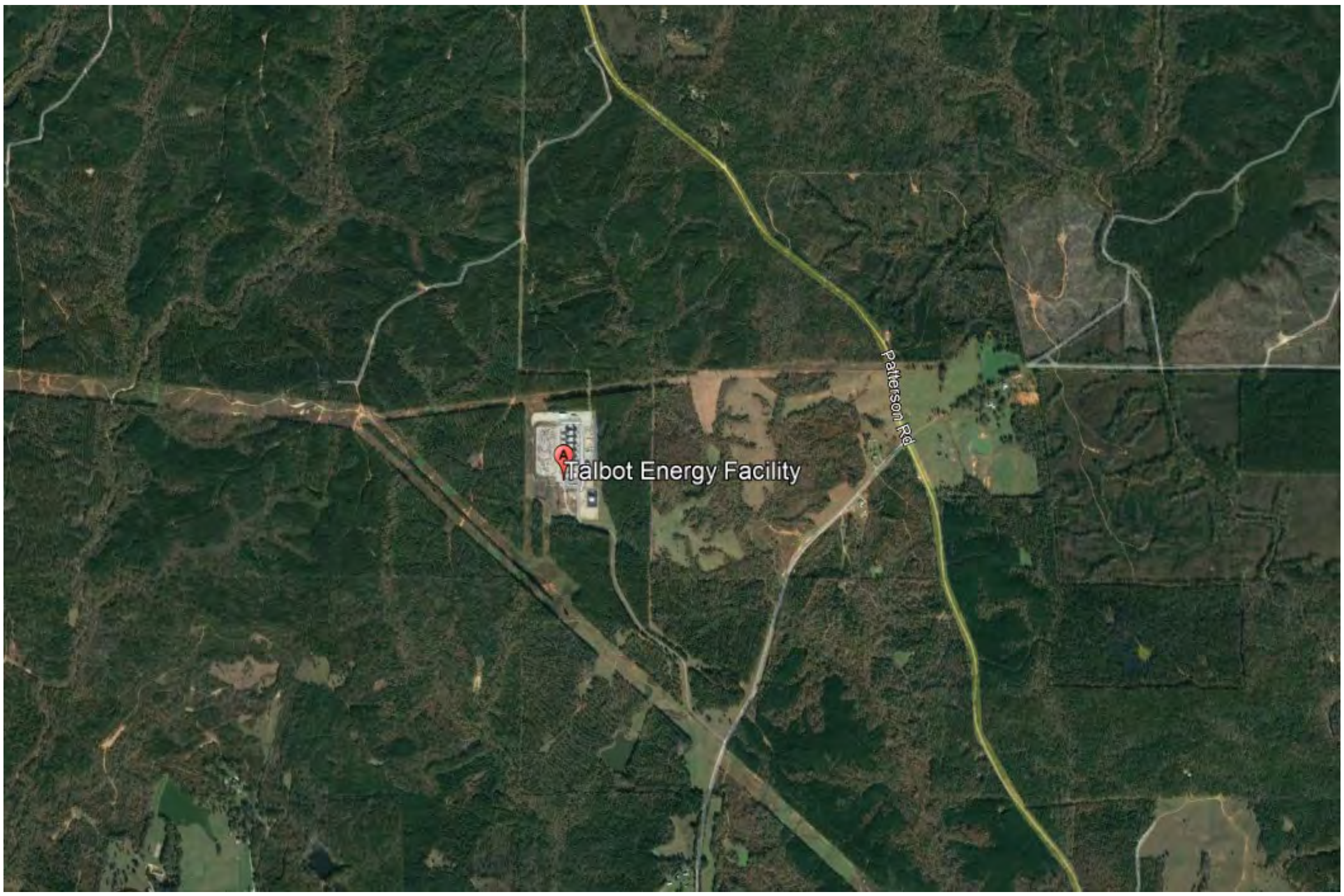
[1] The facility is currently a PSD major source, driven largely by facility NOx emissions. The facility is not classified as one of the 28 named source categories, and is subject to a 250 tpy PSD major source threshold.

[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.

2. PROJECT LOCATION DESCRIPTION

Figure 2-1. provides a map of the area surrounding the proposed project location. The approximate central Universal Transverse Mercator (UTM) coordinates of the facility (centered around the emissions sources) are 716.591 kilometers (km) East and 3,608.001 km North in Zone 16 (NAD 83). The area surrounding the facility is predominantly rural.

Figure 2-1. Project Site Location Map



The property boundary area (ambient air boundary) of the facility is completely fenced and access to the entirety of the property is via the access road at the south end of the property. The fence line boundary of the facility is shown in **Figure 2-2** (yellow line visible drawn around the facility).

Figure 2-2. Facility Ambient Air Boundary and General Site Layout

3. 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). Talbot County, where the facility is located, is currently designated as unclassifiable or in attainment for all criteria pollutants; so, this project is subject to PSD permitting rather than non-attainment New Source Review (NSR).[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 3-1. 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

[3] 40 CFR §81.311

[4] The project emissions increase estimates for the proposed project are preliminary and are subject to change.

4. 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, June 2022)
- AERMOD Implementation Guide (EPA, June 2022)
- 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)
- *Guidance for Ozone and Fine Particulate Matter Modeling* (EPA, Memorandum from Mr. Richard A. Wayland, July 29, 2022)
- *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, 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 $PM_{2.5}$ 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).

4.1 Class II 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 <u>only the emissions increase from new, modified, or associated sources</u> comprising the project; no existing unmodified or unassociated sources are included, nor are sources from other regional facilities.

"Significant" impacts are defined by design concentration thresholds commonly referred to as the SIL. OPC will model the project associated sources for significance. For this project, significance modeling will include the four simple cycle combustion turbines (T1-T4, as modified units) for the use of fuel oil. Additional usage of the fuel heaters (used only for natural gas) is not anticipated as part of this project.[5] The future potential/allowable emissions of each modified 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. Emissions estimates for CTs T1-T4 from the use of fuel oil and from the use of 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 the total annual emissions from the use of both fuel oil and natural gas) for CTs T1-T4 will be derived and carried through all annual average analyses.

1. Future potential emissions will be based on the maximum capacity of each modified 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 modified 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 will be used 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) will be used 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).

Table 4-1 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]

[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 short (less than an hour). 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 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.

[7] Class I analyses are addressed in a following section.

Table 4-1. 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 μg/m³, and an annual SIL of 0.2 μg/m³. 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 highest 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 Per current EPA guidance, this methodology will be utilized for both assessment of the SIL for NAAQS and PSD Increment for $PM_{2.5}$.

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. Significant receptors for each pollutant/averaging period, will be carried through to the respective NAAQS and PSD Increment analyses.

If modeled impacts are greater than the SIL, a full NAAQS and PSD Increment analysis will be performed for that pollutant, averaging period, and fuel type to evaluate whether the project will cause or contribute to any exceedances.

4.2 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 EPA established PSD Increments for PM_{10}, $PM_{2.5}$, and NO_2. The PSD Increments are further broken into Class I, II, and III Increments. Since all short-term Class II Increments (**Table 4-2**) are not to be exceeded more than once per year, the highest 2nd high (H2H) modeled impacts for 24-hr averaging periods for respective pollutants from among the five modeled meteorological years will be compared against the short-term Increment.[8] The highest annual average concentrations will be compared against the annual Increment.

Table 4-2. Class II Increments

Pollutant	Averaging Period	Class II Increment (µg/m³)
$PM_{2.5}$	24-hr Annual	9 4
PM_{10}	24-hr Annual	30 17
NO_2	Annual	25

4.3 Class I Area Significance 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 following Class I areas are located within 300 km of the facility (with the approximate distance to the facility listed):[9]

- Cohutta Wilderness – 249.82 km
- Bradwell Bay Wilderness – 261.54 km
- Saint Marks Wilderness – 273.41 km
- Okefenokee Wilderness – 277.16 km

All other Class I areas are located at distances greater than 300 km from the facility.

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.

[8] The 24-hr increment standards for all criteria pollutants are deterministic standards, meaning they cannot be exceeded more than once per year. https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990; Section 9.2.2 of 40 CFR Part 51, Appendix W (2017)

[9] All distances approximately based on data obtained from the Class I Area distance tool as published by the Florida Department of Environmental Protection (DEP) at https://floridadep.gov/air/air-business-planning/content/class-i-areas-map

- Since the Class I areas above are greater than 50 km away from the facility, a screening procedure will be utilized evaluating an array of receptors located at 50 km from the facility at 1-degree intervals in the direction of the Class I area, to compare project emission increase impacts to those receptors at those distances with the use of AERMOD.[10]

The Class I area SILs and PSD Increment thresholds are listed in **Table 4-3**. Secondary $PM_{2.5}$ impacts will be estimated using the procedures discussed in **Section 4.4**, for the $PM_{2.5}$ SIL analysis.

Table 4-3. Class I SILs and Increment Thresholds

Pollutant	Averaging Period	Class I SIL (µg/m³)	Class I Increment (µg/m³)
$PM_{2.5}$	24-hr	0.27	2
	Annual	0.05	1
PM_{10}	24-hr	0.3	8
	Annual	0.2	4
NO_2	Annual	0.1	2.5

4.4 Modeled Emission Rates for Precursors (MERPs)

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). Similarly, both NO_2 and SO_2 are considered precursors for PM2.5, as those pollutants can react atmospherically to form solid phase particulates such as ammonium sulfate and ammonium nitrate.

EPA 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 to illustrate that a project will not cause or contribute to any violation of ambient ozone standards.[11] 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 GAEPD February 2019 guidance.

[10] This assumes that the applicable Federal Land Manager (FLM) has determined that no air quality related value (AQRV) analyses will be required for the project for the Class I areas of interest. The latest version of the AERMOD model (v22112) will be used for the ring analysis for Class I areas.

[11] https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf

The GAEPD's February 2019 guidance on MERPs procedures also establishes a state-specific Tier 1 procedure for a 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, considering both NO_2 and SO_2.

4.5 Class I Air Quality Related Values (AQRVs)

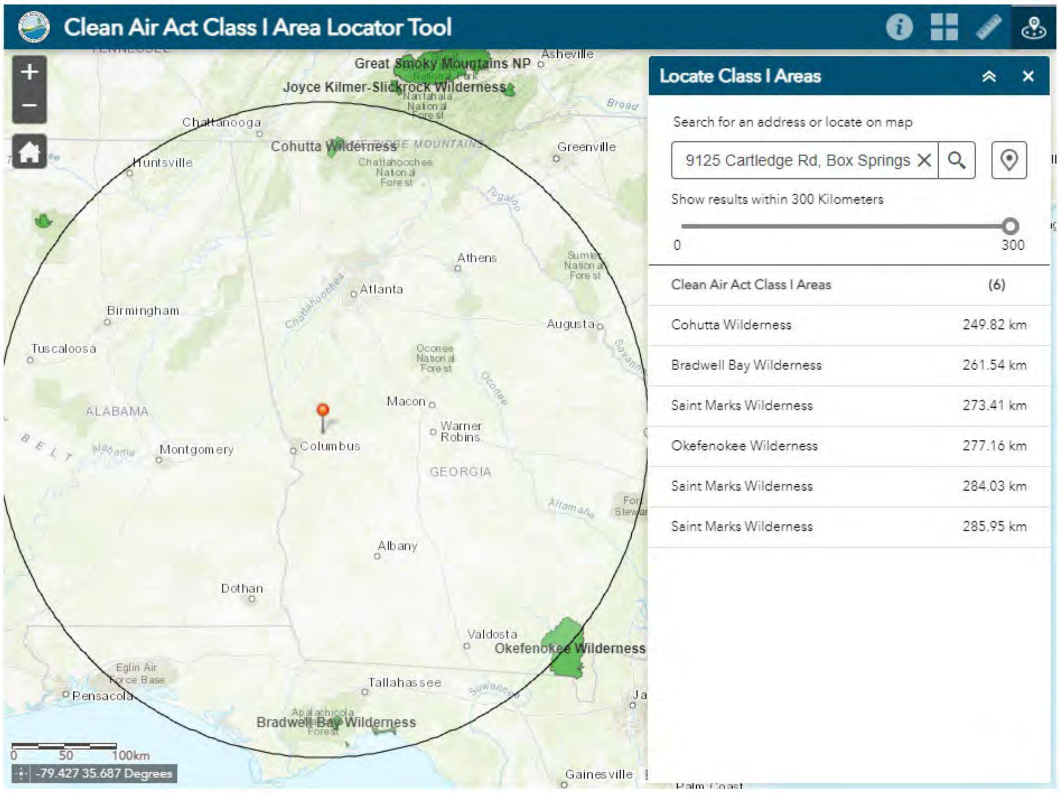
Class I areas are federally protected areas for which more stringent air quality standards apply to protect unique natural, cultural, recreational, and/or historic values. The following Class I area is located within 300 km of the facility (with the approximate distance to the facility listed):[12]

- Cohutta Wilderness – 249.82 km
- Bradwell Bay Wilderness – 261.54 km
- Saint Marks Wilderness – 273.41 km
- Okefenokee Wilderness – 277.4 km

All other Class I areas are located at distances greater than 300 km from the facility. **Figure 4-1** illustrates the facility location in relation to the Class I area of interest.

[12] All distances approximately 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

Figure 4-1. Class I Areas Within 300 km of the Facility



The Federal Land Managers (FLM) have the authority to consider, in consultation with the permitting authority, whether a proposed major emitting facility will have an adverse impact on air quality related values (AQRVs). AQRVs for which PSD modeling is typically conducted include visibility and deposition of sulfur and nitrogen.

The ratio of project-based emissions to Class I distance (i.e., Q/D) for this project for the Class I area 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.[13] A notification will be submitted (via e-mail) to the appropriate FLMs for the Class I area located within 300 km for concurrence with a finding regarding any requirement for a AQRV analysis for this project.[14] The Q/D for the Class I Areas of interest have been evaluated and demonstrated that impacts will be less than 10. The current Q/D derivation for the Class I Areas of interest is identified in **Table 4-4** and **Table 4-5**.

[13] 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.

[14] GAEPD will be copied on all correspondence as provided to the appropriate FLMs. If GAEPD 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.

Table 4-4. Worst Case "Q" Emissions Derivation

Pollutant	Facility-Wide 24-hr Emissions (lb/hr)	FLAG 2010 Approach Annual Emissions[2] Q (tpy)
NO_X	147.95	648
Direct Particulate[1]	55.02	241
SO_2	1.14	5
H_2SO_4	0.23	1
Sum of Emissions (tpy)		1,866.7

1. Direct particulate includes all filterable and condensable PM_{10}.

2. FLAG 2010 Approach: Q = Sum of allowable emissions of project sources * 8,760/4,200 hrs. for limited source operation. Values listed (tpy) are total tpy allowable emissions for the project sources during limited source operation.

Table 4-5. Q/D Values for All Class I Areas Within 300 km

Class I Area	Responsible FLM	Minimum Distance from Site - D (km)	Sum of Annual Emissions - Q (tpy)	Flag 2010 Approach Q/D
Cohutta Wilderness	USFS	249.8	1,866.7	7.47
Bradwell Bay Wilderness	USFS	261.5	1,866.7	7.14
Saint Marks Wilderness	USFWS	273.4	1,866.7	6.83
Okefenokee Wilderness	USFWS	277.2	1,866.7	6.74

4.6 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, NO_2, and PM_{10} are provided in 40 CFR §52.21(i)(5)(i) and are listed in **Table 4-1**.

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 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 $PM_{2.5}$. Therefore, for this project, the existing ambient background monitoring network for $PM_{2.5}$ in the State of Georgia will be sufficient.

4.7 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 will be performed. 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. OPC will use EPD's "PSD Modeling Tool" to obtain the off-site inventory sources necessary for the analysis.[15] OPC will consider only those 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 or within the impact area itself.

OPC 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 be 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 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…"*.[16] Therefore, for this project, if the SIL for 1-hr NO_2 is exceeded, and impacts proceed out to a total distance of 50 km from the site, the significant impact area be concluded at 50 km and all significant receptors within 50 km of the site be evaluated as part of the 1-hr NO2 NAAQS analysis. This also means that all identified major sources, within 50 km of the project site, will automatically be included in the modeling analysis [17]

4.8 Background Concentrations

GAEPD publishes background concentration values on their website and the data for those background monitors as specified by the Georgia EPD will be utilized, with exceptions noted below. [18] The chosen background values are shown in **Table 4-6**.

The Macon, Georgia $PM_{2.5}$ and ozone monitoring location (Georgia Forestry Commission) was chosen based on the surrounding location of the monitors which is primarily rural and is located east of the metropolitan area of Macon.[19] This is a similar geographic location of the Talbot Energy Facility, located to the east of a major metropolitan area (Columbus). Although there are $PM_{2.5}$ and ozone monitors located in the Columbus area, those monitors are located in a more urban environment, and not representative of the more rural

[15] https://psd.georgiaair.org/inventory

[16] Appendix W, Section 8.3.3.b.iii

[17] At a distance of greater than 50 km, 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.

[18] https://epd.georgia.gov/georgia-background-data If more up to date background data is available, that information is requested from the Georgia EPD.

[19] Monitor locations obtained from U.S. EPA AirData: https://www.epa.gov/outdoor-air-quality-data/monitor-values-report

setting of the Talbot Energy Facility east of the metropolitan area of Columbus. Use of background data from these monitors should be sufficiently conservative for this analysis.

In **Table 4-6**, PM_{10}, CO, and NO_2 data are based on statewide background concentration values as provided by the Georgia EPD ambient background data posted on their website. The ozone and $PM_{2.5}$ ambient background data is representative of 2020-2022 design value data, as obtained from the EPA Air Data website, for the Georgia Forestry Commission monitoring location.

Table 4-6. Selected Background Concentrations

PSD Pollutant	Averaging Period	Monitor Background Concentration (μg/m³)	Metric	Monitor Location
PM_{10}	24-hour	30.0	4th high value over 3-yrs	Statewide Value as Derived by EPD (Fire Station #8)
$PM_{2.5}$	24-hour	19.8	3-yr average of 98th percentile	Georgia Forestry Commission, 5645 Riggins Mill Road, Dry Branch, Georgia
	Annual	8.3	3-yr arithmetic mean average	
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	
CO	1-hour	1,068	3-yr average of yearly 2nd high	Statewide Value as Derived by EPD (Yorkville)
	8-hour	839		
Ozone	8-hour	0.058 (ppmv)	Annual 4th highest daily maximum 8-hr value, 3-yr average	Georgia Forestry Commission, 5645 Riggins Mill Road, Dry Branch, Georgia

5. CLASS II MODELING SETUP

5.1 Model Selection – AERMOD

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 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, OPC 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*.

The latest version (v22112) of the AERMOD modeling system will be used to estimate maximum ground-level concentrations in all 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.[20] 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.[21] 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.[22]

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 (v18081) 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.

[20] 40 CFR Part 51, Appendix W, Guideline on Air Quality Models, Appendix A.1 AMS/EPA Regulatory Model (AERMOD).

[21] Earth Tech, Inc., Addendum to the ISC3 User's Guide, The PRIME Plume Rise and Building Downwash Model, Concord, MA.

[22] 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.

AERMET (v22112) 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.

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). Any sources to be evaluated in this modeling assessment with vertical obstructed releases will be evaluated using the appropriate options for horizontal or capped point sources within AERMOD.

5.2 Modeled Sources

OPC will model the project-associated sources for the significance analysis. This includes the facility's four simple cycle combustion turbines (T1-T4) that will be modified as part of this project.

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 will be performed (cumulative impact analysis). For the cumulative impact analysis, all sources at the facility and the appropriate inventory sources will be included. No emergency equipment will be evaluated as part of the modeling analyses.[23]

5.3 Receptor Grid and Coordinate System

Modeled concentrations will be calculated at ground-level receptors placed along the facility's 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 not accessible to the general public 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 NAAQS and Increment modeling. OPC 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 1/3-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 16, NAD-83.

[23] *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)

5.4 Urban versus Rural Dispersion Options

Classification of land use in the immediate area surrounding a facility is important in determining the appropriate dispersion coefficients to select for a particular modeling application. The selection of either rural or urban dispersion coefficients for a specific application should follow one of two procedures. These include a land use classification procedure or a population-based procedure to determine whether the area is primarily urban or rural.[24]

Of the two methods, the land use procedure is considered more definitive. The land use within the total area circumscribed by a 3-km radius circle around the facility was classified using the land use typing scheme proposed by Auer. If land use types 23 (Developed, Medium Intensity), or 24 (Developed, High Intensity) account for 50% or more of the circumscribed area, urban dispersion coefficients should be used; otherwise, rural dispersion coefficients are appropriate.

AERSURFACE (v20060) was used for the extraction of the land-use values in the domain. The results of the land use analysis evaluation were as follows.

Each USGS NLCD 2016 land use class was compared to the most appropriate Auer land use category to quantify the total urban and rural area. **Table 5-1** summarizes the results of this land use analysis. As approximately 99.4% of the area can be classified as rural, the use of rural dispersion coefficients is justified.

[24] 40 CFR Part 51, Appendix W, the Guideline on Air Quality Models (January 2017) – Section 7.2.1.1(b)(i)

Table 5-1. Summary of Land Use Analysis

Category ID	Category Description	Number of Grid Cells	Percent	Dispersion Class
11	Open Water	118	0.4%	Rural
21	Developed, Open Space	938	3.0%	Rural
22	Developed, Low Intensity	244	0.8%	Rural
23	Developed, Medium Intensity	70	0.2%	Urban
24	Developed, High Intensity	103	0.3%	Urban
31	Barren Land	24	0.1%	Rural
41	Deciduous Forest	5,811	18.5%	Rural
42	Evergreen Forest	14,600	46.5%	Rural
43	Mixed Forest	2,079	6.6%	Rural
52	Shrub/Scrub	2,852	9.1%	Rural
71	Grassland/Herbaceous	3,178	10.1%	Rural
81	Pasture/Hay	869	2.8%	Rural
82	Cultivated Crops	0	0.0%	Rural
90	Woody Wetlands	537	1.7%	Rural
95	Emergent Herbaceous Wetlands	6	0.0%	Rural
	Total	31,429	100%	
	Urban		0.6%	
	Rural		99.4%	

Therefore, AERMOD will be evaluated considering rural dispersion coefficients.

5.5 Meteorological Data

Site-specific dispersion models require a sequential hourly record of dispersion meteorology representative of the region within which the source is located. In the absence of site-specific measurements, the EPA guidelines recommend the use of readily available data from the closest and most representative National Weather Service (NWS) station. Regulatory air dispersion modeling using AERMOD requires five years of quality-assured meteorological data that includes hourly records of the following parameters:

- Wind speed;
- Wind direction;
- Air temperature;
- Micrometeorological parameters (e.g., friction velocity, Monin-Obukhov length);
- Mechanical mixing height; and
- Convective mixing height.

The first three of these parameters are directly measured by monitoring equipment located at typical surface observation stations. The friction velocity, Monin-Obukhov length, and mixing heights are derived from characteristic micrometeorological parameters and from observed and correlated values of cloud cover, solar insulation, time of day and year, and latitude of the surface observation station. Surface observation stations form a relatively dense network, are almost always found at airports, and are typically operated by the NWS. Upper air stations are fewer in number than surface observing points since the upper atmosphere is less vulnerable to local effects caused by terrain or other land influences and is therefore less variable. The NWS operates virtually all available upper air measurement stations in the United States.

The *Guideline* states in Section 8.4.2(e), “Meteorological Input Data – Recommendations and Requirements” that:

> *The use of 5 years of adequately representative NWS or comparable meteorological data, at least 1 year of site-specific, or at least 3 years of prognostic meteorological data, are required.*

The meteorological data that are “representative” for a particular facility may be determined using qualitative and quantitative procedures, and the Guideline offers the following guidance in Section 8.4.1(b).

> *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 Talbot County, GA. EPD has provided the most recent five years of meteorological data on their website.[25] 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 Talbot County, GAEPD provides surface data from the Columbus Metropolitan Airport, and upper air data from Peachtree City/Falcon Field. The Columbus Metropolitan Airport meteorological station is located at 32.516 degrees (latitude) and -84.942 degrees (longitude) and is approximately 25 km Southwest of the facility. Meteorological data sets provided by GAEPD covered the time period from 2017 to 2021, and include meteorological data processed both with and without the ADJ_U* option of AERMET. The 2017 to 2021 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.

A comparison of the surface characteristics of both the site and the Columbus, Georgia surface station (KCSG), using data output from AERSURFACE (v20060) is shown below in **Table 5-2**. Results are generally comparable for various parameters (e.g., albedo values) and as such show that the proposed meteorological data set is representative of the proposed project site.

[25] 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.

Table 5-2. Comparison of Site and Airport Surface Characteristics

	Albedo								Albedo			
	Columbus 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	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.15	-13%	-7%	-7%	-7%

	Bowen Ratio								Bowen Ratio			
	Columbus 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	0.99	0.77	0.74	0.99	0.86	0.61	0.38	0.86	-15%	-26%	-95%	-15%
Dry	2.36	1.93	1.82	2.36	1.69	1.36	0.81	1.69	-40%	-42%	-125%	-40%
Wet	0.58	0.52	0.52	0.58	0.38	0.31	0.25	0.38	-53%	-68%	-108%	-53%

	Surface Roughness Length (m)								Surface Roughness Length (m)			
	Columbus 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	0.156	0.191	0.221	0.199	0.577	0.609	0.631	0.623	73%	69%	65%	68%
30 - 60	0.152	0.178	0.199	0.179	0.614	0.724	0.793	0.784	75%	75%	75%	77%
60 - 90	0.079	0.101	0.129	0.112	0.176	0.285	0.352	0.349	55%	65%	63%	68%
90 - 120	0.213	0.260	0.305	0.280	0.227	0.341	0.410	0.408	6%	24%	26%	31%
120 - 150	0.173	0.217	0.256	0.231	0.417	0.540	0.613	0.606	59%	60%	58%	62%
150 - 180	0.205	0.246	0.280	0.257	0.451	0.516	0.664	0.657	55%	52%	58%	61%
180 - 210	0.141	0.165	0.184	0.165	0.394	0.505	0.678	0.671	64%	67%	73%	75%
210 - 240	0.150	0.175	0.195	0.176	0.522	0.599	0.736	0.723	71%	71%	74%	76%
240 - 270	0.145	0.169	0.189	0.169	0.438	0.544	0.604	0.595	67%	69%	69%	72%
270 - 300	0.259	0.286	0.307	0.286	0.287	0.422	0.503	0.497	10%	32%	39%	42%
300 - 330	0.146	0.175	0.200	0.179	0.384	0.430	0.458	0.450	62%	59%	56%	60%
330 - 360	0.130	0.162	0.191	0.170	0.323	0.394	0.435	0.427	60%	58.9%	56%	60%
Average	0.162	0.194	0.221	0.200	0.401	0.492	0.573	0.566	59%	61%	61%	65%

5.6 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.

5.7 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). Any facility sources to be evaluated in this modeling assessment with vertical obstructed releases will be evaluated using the appropriate options for horizontal or capped point sources within AERMOD.

5.8 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.[26] A preliminary evaluation has indicated that none of the Facility emission unit stacks will exceed GEP height.

5.9 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. OPC will use EPD's "PSD Modeling Tool" to obtain the off-site inventory sources necessary for the analysis.[27] OPC will consider only 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 or within the impact area distance.

OPC 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 be 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 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…"*.[28] Therefore, for this project, if the SIL for 1-hr NO_2 is exceeded, and impacts proceed out to a total distance of 50 km from the site, the significant impact area be concluded at 50 km and all significant receptors within 50 km of the site be evaluated as part of the 1-hr NO_2 NAAQS analysis. This also means that all identified major sources, within 50 km of the project site, will automatically be included in the modeling analysis [29]

[26] 40 CFR §51.100(ii)

[27] https://psd.georgiaair.org/inventory

[28] Appendix W, Section 8.3.3.b.iii

[29] At a distance of greater than 50 km, 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. Given the proximity of the project site to Alabama, a modeling inventory for 1-hr NO_2 modeling, for sources within 50 km of the project site, has been requested from ADEM.

5.10 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. OPC 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), OPC 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.

5.11 Startup/Shutdown Modeling and Variable Load Modeling

Startup/Shutdown modeling will not be conducted for project significance modeling, as startup/shutdown activities are all sub-hourly events 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 different load cases 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.

6. ADDITIONAL IMPACTS ANALYSIS

Three additional impacts analyses are generally performed as part of the PSD permitting action. These are: 1) a growth analysis, 2) a soil and vegetation analysis, 3) a visibility analysis, and 4) a toxic impact assessment.

6.1 Growth Analysis

The purpose of the growth analysis is to quantify project associated growth; that is, to predict how much new growth is likely to occur in order to support the source or modification under review, and then to estimate the air quality impacts from this growth. Accordingly, OPC will include a discussion of impacts resulting from residential and commercial growth driven by the proposed project in the PSD permit application.

6.2 Soils and Vegetation Analysis

The EPA developed the secondary NAAQS to protect certain air quality related values (i.e., soil and vegetation) that may not be sufficiently protected by the primary NAAQS. The secondary NAAQS, shown in **Table 4-1** represent levels that provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

To assess soil and vegetation impacts, the modeling results from the NAAQS analysis will be primarily assessed against the secondary NAAQS standards. While OPC intends to primarily assess the impacts to soils and vegetation based on an evaluation of compliance with the secondary NAAQS, potential impacts will also be evaluated using the methodology outlined in the EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*.[30] In this document, EPA developed a set of screening thresholds that are used to assess the potential for adverse impacts on soils and vegetation due to various types of air emission sources. EPA has not released any new editions of this document since it was first published in 1980 and it is still widely utilized by applicants and agencies for these types of analyses.

6.3 Visibility Analysis

No Class II visibility areas of concern (e.g., state parks, airports) are anticipated to be within the significant impact areas derived for the project for PM_{10}, $PM_{2.5}$, or annual NO_2. Therefore, no Class II visibility assessment is anticipated to be required for this project. If a Class II visibility analysis is required, the VISCREEN model will be utilized in accordance with GAEPD guidance.

6.4 Toxic Air Pollutant Modeling

GAEPD 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

[30] EPA, Office of Air Quality Planning and Standards, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants Soils and Animals*, Research Triangle Park, North Carolina, December 1980.

reviews are contained in EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (the *Toxics Guideline*).[31]

The *Toxics Guideline* describes 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 calculcated by EPD by using worst-case dispersion scenarios and using the SCREEN3 computer air dispersion model. The MERs were calculated 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 compared to the MERs. If a pollutant's facility-wide emission rate is below the MER, no further analysis will be needed for that pollutant. For any pollutant whose emission rate is above its respective MER, OPC 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.

[31] *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*. Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Revised, May 2017.

7. SUMMARY AND APPROVAL OF MODELING PROTOCOL

OPC 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 can request any additional information. OPC 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.

GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Richard E. Dunn, Director

Air Protection Branch
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May 4, 2023

Mr. Justin Fickas, P.E.
Principal Consultant
Trinity Consultants
Tel: 678-441-9977
JFickas@trinityconsultants.com

Subject: **Review of PSD Air Dispersion Modeling Protocol**
Oglethorpe Power Corporation Talbot Energy Facility, Box Springs, Talbot County, GA (AIRS# 263-00013)

Dear Mr. Fickas:

Georgia Environmental Protection Division (GA EPD) has reviewed the air quality dispersion modeling protocol received on April 3, 2023, from Talbot Energy Facility (Talbot Energy) owned and operated by Oglethorpe Power Corporation located in Box Springs, GA (Talbot County). We find that the submitted protocol generally conforms to the procedures and guidelines we use to assess PSD and toxic air pollutant (TAP) impact modeling projects. However, we do have comments on the submitted modeling protocol (Attachment 1).

This protocol approval is valid for 6 months from today, unless otherwise stipulated, and is based on the condition that Talbot Energy addresses all comments described in Attachment 1. If you have any questions, please contact Byeong-Uk Kim at Byeong.Kim@dnr.ga.gov or 470-524-0734.

Sincerely,

Byeong-Uk Kim, Ph.D.
Manager, Data & Modeling Unit
Georgia Department of Natural Resources
Environmental Protection Division – Air Protection Branch

ATTACHMENT 1: GA EPD's Comments and Recommendations on the Submitted Modeling Protocol
ATTACHMENT 2: Generally Applicable Modeling References
ATTACHMENT 3: Example of Rural/Urban Determination

ATTACHMENT 1
GA EPD's Comments and Recommendations on the Submitted Modeling Protocol

Note that some GA EPD comments and recommendations listed below are included with all modeling protocol approval letters.

Please refer to Appendices A and B of the "Georgia EPD PSD Permit Application Guidance Document" (GA PSD Guidance Document) for completeness of your PSD application. If EPA issues any guidance or models which you believe may affect the modeling of this project after you receive this protocol approval letter, please contact GA EPD to verify the ability to incorporate such guidance or models in the assessments in this application. If you have specific questions regarding issues that develop after you receive this protocol approval letter, please contact GA EPD.

GA EPD requests that the applicant submit all modeling inputs and outputs in electronic format. The applicant should ensure consistency of emission information (e.g., emission source IDs, emission rates, and source parameters) between a modeling report and modeling files. In addition, GA EPD recommends that the applicant submit spreadsheet versions of modeled emissions that show details of emission calculations for on-site and off-site sources as applicable to expedite GA EPD's review.

During the application review, the DMU may choose different modeling options and/or inputs if those options and/or inputs are considered the best available information and/or what the DMU recommends in this protocol approval letter. Examples include background concentrations. If the DMU finds any significant differences in its modeling results compared with what the applicant has submitted, the DMU will notify the applicant about DMU's findings before finalizing its review.

1 INTRODUCTION
GA EPD does not have comments on this section.

2 PROJECT LOCATION DESCRIPTION
The facility is a peaking power plant located in a predominantly rural area of Talbot County. The facility is completely fenced in, and access to the facility is only possible via an access road located at the south end of the property. Based on this description and the image shown in Figure 2-2 of the modeling protocol, the GA EPD concurs that the applicant's defined ambient air boundaries align with EPA's ambient air policy dated December 2, 2019.[1]

3 PSD APPLICABILITY
Emission calculations used to determine modeled emission rates should include documentation (e.g., emission factors and utilization) for all applicable PSD pollutants. This will allow GA EPD to promptly review and approve emissions estimates for modeled emission units. Table 8.2 of Appendix W requires that emissions modeled in the significant impact analysis reflect the post-project potential emission rates for all new, modified, or associated units. Please note that total $PM_{2.5}$ emissions include all filterable and condensable (e.g., sulfuric acid mist) $PM_{2.5}$ emissions.

[1] https://www.epa.gov/nsr/ambient-air-guidance

4 PSD MODELING ANALYSES

4.1 Class II Significance and NAAQS Analysis

The applicant proposes to determine the significant impact by considering the net emissions increase per pollutant. The worst-case scenario is determined with variable-load modeling and the worst-case emission scenario should be used to conduct air quality impact modeling assessment. The applicant should provide sufficient explanations about how the SIA is determined and should specify the AERMOD source types used to represent applicable sources.

The modeling protocol states that the applicant will model different load cases and select the worst-case scenario for each applicable pollutant and averaging time combination. However, the applicant does not intend to consider start-up and shutdown scenarios when conducting this evaluation, as start-up and shutdown activities are each sub-hourly events. To exclude modeling start-up and shutdown emissions, the applicant should provide additional documentation including the expected number of start-ups and shutdowns, expected emission levels – particularly if the applicant expects that emissions will be considerably larger during start-up – and whether emissions can be reliability quantified for start-up and shutdown activities.

GA EPD generally concurs the proposed approach to derive past actual emissions. However, GA EPD reminds the applicant that modeling should use past actual emissions based on the most recent two years of operation. If the most recent two years are not representative for actual operations, GA EPD strongly recommends that the applicant consult with GA EPD for alternatives.

Page 4-3 references “Table 2.” However, GA EPD cannot find the table.

4.2 Class II Increment Analysis

GA EPD reminds the applicant that secondary $PM_{2.5}$ should be included in an increment analysis of $PM_{2.5}$ and PM_{10} as applicable.

4.3 Class I Area Significance Analysis

GA EPD generally concurs with the applicant’s proposed approach to use AERMOD for the Class I area increment screening modeling for applicable air pollutants. GA EPD reminds the applicant that no building downwash should be employed for the Class I area modeling. The applicant needs to conduct the Class I area increment screening modeling for $PM_{2.5}$ and PM_{10} including secondary $PM_{2.5}$ as well. The applicant can apply distance-based MERPs to the Class I area increment screening modeling for $PM_{2.5}$ and PM_{10}.

4.4 Modeled Emission Rates for Precursors (MERPs)

For MERPs, the applicant should follow the EPA’s “Guidance for Ozone and Fine Particulate Matter Modeling” (July 29, 2022) and *Guidance on the Use of EPA’s MERPs to Account for Secondary Formation of Ozone and PM2.5 in Georgia*. The applicant should consult with GA EPD to ensure that the latest hypothetical source data are chosen from EPA’s Qlik site[2] and the selected hypothetical source best represents the facility.

4.5 Class I Air Quality Related Values (AQRVs)

The applicant is reminded to submit a notification of the proposed PSD project to the applicable Federal

[2] https://www.epa.gov/scram/merps-view-qlik

Land Manager(s) (FLM) for any Class I areas within 300 km of the proposed site. The content of this notification should include all applicable requirements specified in the 2010 Federal Land Managers' Air Quality Related Values (AQRVs) Work Group report[3]. Copy EPA Region 4 and GA EPD on any project correspondence with any FLM to avoid delays in the modeling review process.

4.6 Ambient Monitoring Requirements

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.

4.7 Regional Source Inventory (Class II Modeling)

GA EPD reminds the applicant that the search radius for off-site inventory sources should be SIA plus 50 km, not 50 km. Please check GA PSD Guidance Document for details. In addition, GA EPD reminds the applicant to model all sources listed in the AERMOD files generated by the PSD Inventory Tool, including sources listed in the "Exempt" tab of the associated Excel spreadsheet.

GA EPD recommends that the applicant exercise professional judgment when including any major NO_X sources just beyond the SIA distance in the modeling inventory. In general, the applicant can limit the initial screening area for 1-hour NO_2 to 10 km based on the March 2011 EPA guidance memo. However, if there are large sources beyond 10 km from Talbot Energy that may contribute to a violation of the 1-hour NO_2 NAAQS, it may be necessary to include these large sources in the cumulative 1-hour NO_2 NAAQS modeling. If any questions arise about the inclusion of sources outside of the SIA, please contact GA EPD to discuss the matter.

4.8 Background Concentrations

The applicant should provide justification for the selected background concentrations to be used. Justification shall include trends of (1) concentrations at the selected monitors and (2) emissions of pollutants in and around the proposed site. GA EPD recommends that the applicant review the section titled "DETERMINING BACKGROUND CONCENTRATIONS" of the EPA memo "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO2, National Ambient Air Quality Standard" (dated March 1, 2011) and the Section 8.3 "Background Concentrations" of Appendix W.

5 CLASS II MODELING SETUP

5.1 Model Selection - AERMOD

GA EPD concurs with the applicant that PSD modeling should use the latest versions of AERMOD (version 22112) and AERMAP (version 18081). As required in the Guideline on Air Quality Models (Appendix W of 40 CFR 51; "Appendix W") dated January 17, 2017, the regulatory default options need to be employed in the modeling unless the use of non-default options is approved by the Environmental Protection Agency (EPA) Region 4 office.

GA EPD generally concurs with the proposed Tier 2 approach to utilize the default ARM2 option in AERMOD for all short- and long-term analyses of NO_2. 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. Please note that the applicant can use Tier 3 approaches such as the Ozone Limited Method (OLM) or

[3] http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

Plume Volume Molar Ratio Method (PVMRM) if a Tier 2 approach produces overly conservative results. Please also note the applicant should consult with GA EPD and EPA Region 4 before using a Tier 3 approach. Additionally, please distinguish between NO_X and NO_2 in the air quality modeling report.

5.2 Modeled Sources

The modeling protocol indicates Talbot Energy will modify four simple cycle combustion turbines (T1-T4). The worst-case modeled impacts for each pollutant will be identified using variable load modeling. Based on Georgia PSD guidance (Section 5.2.4), the suggested load modeling for a project should be outlined in the permit application. Relevant stack test parameter data should be included in a modeling analysis for the varying load models (e.g., 25%, 50%, and 75%). The need to assess varying operating loads will depend on the equipment being installed and the frequency at which the equipment would operate at reduced loads. In addition, the applicant should address GA EPD comments on start-up and shutdown emissions in the "4.1 Class II Significance and NAAQS Analysis" section above.

Additional justification for exclusion of any intermittent 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.

5.3 Receptor Grid and Coordinate System

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 within an area of 100 m 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. The applicant may use a larger grid spacing if the ultimate design value is determined by re-modeling with a fine 100 m grid around a more coarsely resolved design concentration. All design concentrations close (e.g., equal to or greater than 90%) to the design concentrations should be resolved at the receptors with 100 m or less spacing.

A reduced receptor grid with only the receptors at which maximum modeled concentrations exceed or are equal to the SIL is required to be used for NAAQS and Increment modeling.

If plant-grade elevations are available for fenceline receptors, GA EPD recommends that the applicant use those data. Otherwise, consistent with the approach for base elevations of buildings, the applicant should use AERMAP (version 18081) to assess all model receptor elevations above sea level with the USGS NED database. GA EPD recommends the use of 1/3 arc-second NED database although it is not mandatory.

For the 1-hour NO_2 NAAQS assessment, the applicant should place enough receptors around any receptors that violate the 1-hour NO_2 NAAQS to ensure that no additional 1-hour NO_2 NAAQS violations can occur beyond modeling domains. The applicant must include receptors on elevated locations such as high hills and mountains that are near violating receptors.

5.4 Urban versus Rural Dispersion Options

GA EPD requests that the applicant provide justification for using the rural dispersion coefficient in addition to "Table 5-2 Comparison of Site and Airport Surface Characteristics." Please see

ATTACHMENT 3 which contains an example AERSURFACE script and data analysis table for the applicant's reference.

5.5 Meteorological Data

GA EPD concurs with the applicant about the proposed approach to assess the representativeness of meteorological surface and upper air sites used in modeling.

5.6 Building Downwash Analysis

GA EPD concurs with the applicant's proposal to use BPIPRM (version 04274) to assess building downwash effects. The modeling analysis should provide the information (e.g., "L", the lesser dimension of the structure) used to determine which buildings (including those near the project site) and stacks the applicant included in its BPIPPRM runs. Stacks with heights equal to, or above GEP height should be modeled using the GEP height for all sources subject to building downwash.

If plant-grade elevations are available for buildings and emission release points, GA EPD recommends that the applicant use those data. Otherwise, the applicant should use AERMAP to assess base elevations above sea level with the USGS NED data files for all emission release points and buildings. GA EPD recommends the use of 1/3 arc-second NED database although it is not mandatory. If base elevations of building corners are estimated with AERMAP, the applicant should use a representative building base elevation (e.g., average of base elevations of all building corners) for each building. Please note that base elevation of buildings should be consistent between BPIPPRM input and AERMOD input. In addition, the base elevation of any source attached to a building should be consistent with the base elevation of the building.

5.7 Source Types and Parameters

GA EPD concurs with the applicant about the proposed approach.

5.8 GEP Stack Height Analysis

GA EPD concurs with the applicant about the proposed approach.

5.9 Regional Source Inventory (Class II Modeling)

The initial radius for the off-site inventory is the radius for the pollutant-specific largest SIA, excluding 1-hr NO_2 and 1-hr SO_2) plus 50 km. GA EPD reminds the applicant to model all sources listed in the AERMOD files generated by the PSD Inventory Tool, including sources listed in the "Exempt" tab of the associated Excel spreadsheet.

In general, the applicant can limit the initial screening area for 1-hour NO_2 to 10 km based on the March 2011 EPA guidance memo. However, the applicant may include sources over 10 km for cumulative 1-hour NO_2 NAAQS modeling to ensure sources beyond 10km do not contribute to a violation of the 1-hour NO_2 NAAQS. If any questions arise about the inclusion of sources outside of the SIA, please contact GA EPD to discuss the matter.

The minor source baseline date for annual NO_2 is May 5, 1988. GA EPD recommends that the applicant exercise professional judgment when including any major NO_X sources just beyond the SIA distance in the modeling inventory. The applicant can supplement and correct the initial inventory as necessary with approval from GA EPD. If any missing inventory information is identified, please consult with GA EPD regarding the specific missing data handling technique or use the default parameters. The applicant may propose to use emissions that are different from those 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.

Off-site sources can be screened out from the cumulative analysis using a “20D” approach, provided that these sources are not located within the SIA. All sources within the SIA, including synthetic minor or true minor, should be considered in the cumulative modeling. Details can be found in Section 5.3 of the GA EPD PSD Guidance Document. The applicant should provide written substantiation of the “20D” screening calculations for each applicable exclusion as part of the modeling application. For the 20D screening, GA EPD accepts an approach that groups facilities (not necessarily stacks) located within 2 km from each other. Note that the applicant cannot use the 20D approach for its own emission sources.

The final modeling report should include the supporting information used to justify the exclusion of any emergency or intermittent sources within the SIA.

5.10 NO_2 Modeling Approaches

Other than previous comments, we have no new comments for this section.

5.11 Startup/Shutdown Modeling and Variable Load Modeling

The applicant should address GA EPD comments on (1) start-up and shutdown emissions in the “4.1 Class II Significance and NAAQS Analysis” section above and (2) the variable load modeling approach in the “5.2 Modeled Sources” section above.

6 ADDITIONAL IMPACT AIR QUALITY ANALYSIS

6.1 Growth Analysis

GA EPD concurs with the applicant about the proposed approach to perform the growth analysis.

6.2 Soils and Vegetation Analysis

This analysis is required only for PSD pollutants with modeled concentrations at or above SILs. As a reminder, the applicant can compare total impacts with secondary NAAQS for this analysis. The total impact is a sum of modeled concentrations with appropriate background concentrations.

6.3 Visibility Analysis

In general, GA EPD does not waive additional impact analysis requirements without reviewing and approving appropriate justifications submitted in the application. All additional impact studies will be limited to no more than the largest significant impact distance from the project site. Additional impact studies do not include National Monuments unless specifically requested by a Federal Land Manager. Please check the GA PSD Guidance Document for details.

6.4 Toxic Air Pollutant Modeling

GA EPD reminds the applicant that any TAPs from all ancillary sources should be addressed too. In addition, the minimum emission rate (MER) screening is only applicable when most emissions are from POINT sources.

The most recent version of AERMOD (currently version 22112) needs to be used to model the TAP impacts on air quality. The applicant should conduct air toxics modeling in accordance with the 2017 GA EPD Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (“GA TAP Guidance”). The GA EPD will approve which TAPs need to be assessed. The air toxics modeling needs to include all on-site sources of the same pollutant. Please review the acceptable ambient concentration (AAC) values and their corresponding averaging periods. In addition, the applicant should ensure the use of the most recently updated AAC values. Please document the basis for any updated AAC values as part of the modeling portion of the application. In addition, please consult with the GA EPD for exclusion of any TAPs based on the application of MERs if those TAPs are emitted from release points that are characterized as non-POINT sources.

There should be sufficient receptors to resolve the maximum ground-level concentration (MGLC). If any receptors are located at terrain elevations above the lowest stack height in the model, the applicant should use AERMOD to assess impacts at those receptors. GA EPD recommends that the applicant follow GA TAP Guidance for placing receptors.

If an MGLC for a TAP is above the corresponding AAC, the applicant should conduct a risk analysis. The risk analysis needs to follow the procedures specified in the GA TAP Guidance and examine modeled concentrations at residential area receptors as well as business area receptors.

7 SUMMARY AND APPROVAL OF MODELING PROTOCOL

GA EPD concurs with the applicant about the proposed approach to deliver modeling files. This protocol approval letter is GA EPD's response to the applicant's request for "a written response" to the submitted protocol.

ATTACHMENT 2
Generally Applicable Modeling References

1980, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, EPA 450/2-81-078

1990, Draft New Source Review Workshop Manual.

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.

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.

2010, Federal Land Managers' (FLMs) Air Quality Related Values Work Group (FLAG) Phase I Report - Revised, http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

2010, Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)--Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC), Final rule, Federal Register vol. 75, No. 202, pgs. 64863-64907 (October 20, 2010).

2014, Guidance for $PM_{2.5}$ Permit Modeling, https://www3.epa.gov/scram001/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

2017, Draft Georgia EPD PSD Permit Application Guidance Document, https://epd.georgia.gov/air/georgia-epd-psd-permit-application-guidance-document

2017, Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, https://epd.georgia.gov/air/documents/toxics-impact-assessment-guideline

2017, 40 CFR 51, Appendix W, Revisions to the Guideline on Air Quality Models, https://www3.epa.gov/ttn/scram/appendix_w/2016/AppendixW_2017.pdf

2018, AERMOD Implementation Guide, https://www3.epa.gov/ttn/scram/models/aermod/aermod_implementation_guide.pdf

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

2020, User's Guide for the AERSURFACE Tool, EPA-454/B-20-008, https://gaftp.epa.gov/Air/aqmg/SCRAM/models/related/aersurface/aersurface_ug_v20060.pdf

2022, User's Guide for the AMS/EPA Regulatory Model (AERMOD), EPA-454/B-22-007, https://gaftp.epa.gov/Air/aqmg/SCRAM/models/preferred/aermod/aermod_userguide.pdf

ATTACHMENT 3
Example of Rural/Urban Determination

The selection of rural or urban dispersion coefficients should follow one of the two procedures detailed in Section 7.2.1.1.b of the *Guideline on Air Quality Models 40 CFR 51, Appendix W* (EPA, Revised, January 17, 2017). These include the land use classification procedure and the population density procedure to determine whether the area is primarily rural or urban. The land use classification method is the preferred method.

Below is an example AERSURFACE script that can be used to develop an application specific land use classification analysis.

```
**
CO STARTING
   TITLEONE  Company Name
   TITLETWO  Date, 2016 NLCD

** Using default options for OPTIONS keyword and parameters
   OPTIONS   PRIMARY  ZORAD
   DEBUGOPT  GRID  TIFF
   CENTERLL  33.27048120   -81.93143662   NAD83
   DATAFILE  NLCD2016  "NLCD_2016_Land_Cover_GA.uncompressed.tiff"
   DATAFILE  CNPY2016  "NLCD_2016_Tree_Canopy_GA.uncompressed.tiff"
   DATAFILE  MPRV2016  "NLCD_2016_Impervious_GA.uncompressed.tiff"

** Use 3 km radius
   ZORADIUS  3.0
   CLIMATE   AVERAGE  NOSNOW   NONARID

** Get monthly values for six sectors
** Vary AP/Non-AP sectors
   FREQ_SECT   SEASONAL    6  VARYAP

**         index  start    end
   SECTOR   1   10.00   40.00 NONAP
   SECTOR   2   40.00   80.00 NONAP
   SECTOR   3   80.00  110.00 NONAP
   SECTOR   4  110.00  225.00 NONAP
   SECTOR   5  225.00  255.00 NONAP
   SECTOR   6  255.00   10.00 NONAP

   RUNORNOT  RUN
CO FINISHED

OU STARTING
   SFCCHAR    "aurubis_2016_lc_can_imp_zorad_sfc.txt"
   NLCDGRID   "aurubis_2016_lc_can_imp_zorad_lc_grid.txt"
   CNPYGRID   "aurubis_2016_lc_can_imp_zorad_can_grid.txt"
   MPRVGRID   "aurubis_2016_lc_can_imp_zorad_imp_grid.txt"
OU FINISHED
```

Once the script above is executed, AERSUFACE generates the “aersurface.log” file. Then, the “aersurface.log” file (one of the output files) can be analyzed quantitatively to determine an appropriate dispersion coefficient. The DMU considers Categories 23 and 24 of National Land Cover Database (NLCD) 2016 as “urban.”

	SECTOR:	**1**	**2**	**3**	**4**	**5**	**6**	**Total**	**%**	
Cat	**Starting Direction:**	**10**	**40**	**80**	**110**	**225**	**255**			
11	Open Water:	0	51	7	135	20	35	248	0.79%	Rural
12	Perennial Ice/Snow:	0	0	0	0	0	0	0	0.00%	Rural
21	Developed, Open Space:	188	313	232	1037	310	705	2785	8.87%	Rural
22	Developed, Low Intensity:	22	179	130	964	244	554	2093	6.66%	Rural
23	Developed, Medium Intensity:	0	34	9	770	84	229	1126	3.59%	Urban
24	Developed, High Intensity:	0	6	2	519	38	58	623	1.98%	Urban
31	Barren Land (Rock/Sand/Clay):	8	7	7	46	16	79	163	0.52%	Rural
32	Unconsolidated Shore:	0	0	0	0	0	0	0	0.00%	Rural
41	Deciduous Forest:	966	967	831	2690	724	3989	10167	0.32	Rural
42	Evergreen Forest:	310	265	42	232	29	339	1217	3.88%	Rural
43	Mixed Forest:	364	400	310	843	256	1083	3256	10.37%	Rural
51	Dwarf Scrub:	0	0	0	0	0	0	0	0.00%	Rural
52	Shrub/Scrub:	61	115	116	491	54	310	1147	3.65%	Rural
71	Grasslands/Herbaceous:	262	319	69	299	26	129	1104	3.52%	Rural
72	Sedge/Herbaceous:	0	0	0	0	0	0	0	0.00%	Rural
73	Lichens:	0	0	0	0	0	0	0	0.00%	Rural
74	Moss:	0	0	0	0	0	0	0	0.00%	Rural
81	Pasture/Hay:	369	724	505	1587	785	1405	5375	17.11%	Rural
82	Cultivated Crops:	0	0	0	0	0	0	0	0.00%	Rural
90	Woody Wetlands:	60	108	335	377	29	1044	1953	6.22%	Rural
91	Palustrine Forested Wetland:	0	0	0	0	0	0	0	0.00%	Rural
92	Palustrine Scrub/Shrub Wetland:	0	0	0	0	0	0	0	0.00%	Rural
93	Estuarine Forested Wetland:	0	0	0	0	0	0	0	0.00%	Rural
94	Estuarine Scrub/Shrub Wetland:	0	0	0	0	0	0	0	0.00%	Rural
95	Emergent Herbaceous Wetland:	5	6	24	45	0	69	149	0.47%	Rural
96	Palustrine Emergent Wetland (Pe:	0	0	0	0	0	0	0	0.00%	Rural
97	Estuarine Emergent Wetland:	0	0	0	0	0	0	0	0.00%	Rural
98	Palustrine Aquatic Bed:	0	0	0	0	0	0	0	0.00%	Rural
99	Estuarine Aquatic Bed:	0	0	0	0	0	0	0	0.00%	Rural
	Total:	2615	3494	2619	10035	2615	10028	31406	100.00%	

In this example, the total number of NLCD pixel for urban land use is 1,749 (=1126+623). Because the total number of pixels is 31,406, the percentage of urban areas is 5.6%. It means 94.4% of the area is rural.

APPENDIX D. EMISSIONS INFORMATION FOR MODELING

Table D-1. Load Analysis of Turbines at 100%, 80%, and 70% Load - Natural Gas

Load Case	Model ID	Source Description	Stack Height (ft)	Exit Temperature (F)	Exhaust Flow Rate (acfm)	Exit Velocity (ft/s)	Stack Diameter (ft)	Heat Input (MMBtu/hr)	Hours of Operation (hrs/yr)	SUSD Hours of Operation (hrs/yr)
100%	T1	Turbine No. 1	90.0	1,006	1,766,175	110.7	18.4	1,180	3,750	3,296
	T2	Turbine No. 2	90.0	1,006	1,766,175	110.7	18.4	1,180	3,750	3,296
	T3	Turbine No. 3	90.0	1,006	1,766,175	110.7	18.4	1,180	3,750	3,296
	T4	Turbine No. 4	90.0	1,006	1,766,175	110.7	18.4	1,180	3,750	3,296
80%	T1	Turbine No. 1	90.0	1,006	1,535,451	96.2	18.4	998	3,750	3,296
	T2	Turbine No. 2	90.0	1,006	1,535,451	96.2	18.4	998	3,750	3,296
	T3	Turbine No. 3	90.0	1,006	1,535,451	96.2	18.4	998	3,750	3,296
	T4	Turbine No. 4	90.0	1,006	1,535,451	96.2	18.4	998	3,750	3,296
70%	T1	Turbine No. 1	90.0	1,006	1,432,282	89.8	18.4	912	3,750	3,296
	T2	Turbine No. 2	90.0	1,006	1,432,282	89.8	18.4	912	3,750	3,296
	T3	Turbine No. 3	90.0	1,006	1,432,282	89.8	18.4	912	3,750	3,296
	T4	Turbine No. 4	90.0	1,006	1,432,282	89.8	18.4	912	3,750	3,296

Table D-2. Load Analysis of Turbines at 100%, 80%, and 70% Load - Fuel Oil

Load Case	Model ID	Source Description	Stack Height (ft)	Exit Temperature (F)	Exhaust Flow Rate (acfm)	Exit Velocity (ft/s)	Stack Diameter (ft)	Heat Input (MMBtu/hr)	Hours of Operation (hrs/yr)	SUSD Hours of Operation (hrs/yr)
100%	T1	Turbine No. 1	90.0	1,008	1,864,991	116.9	18.4	1,365	450	3,296
	T2	Turbine No. 2	90.0	1,008	1,864,991	116.9	18.4	1,365	450	3,296
	T3	Turbine No. 3	90.0	1,008	1,864,991	116.9	18.4	1,365	450	3,296
	T4	Turbine No. 4	90.0	1,008	1,864,991	116.9	18.4	1,365	450	3,296
80%	T1	Turbine No. 1	90.0	1,008	1,605,258	100.6	18.4	1,145	450	3,296
	T2	Turbine No. 2	90.0	1,008	1,605,258	100.6	18.4	1,145	450	3,296
	T3	Turbine No. 3	90.0	1,008	1,605,258	100.6	18.4	1,145	450	3,296
	T4	Turbine No. 4	90.0	1,008	1,605,258	100.6	18.4	1,145	450	3,296
70%	T1	Turbine No. 1	90.0	1,008	1,494,549	93.7	18.4	1,044	450	3,296
	T2	Turbine No. 2	90.0	1,008	1,494,549	93.7	18.4	1,044	450	3,296
	T3	Turbine No. 3	90.0	1,008	1,494,549	93.7	18.4	1,044	450	3,296
	T4	Turbine No. 4	90.0	1,008	1,494,549	93.7	18.4	1,044	450	3,296

Table D-3. Modeled Emission Rates for Turbines at 100%, 80%, and 70% Load - Natural Gas

Load Case	Model ID	Description	Short-Term Emissions (lb/hr) CO	NO_x	PM_{10}	$PM_{2.5}$
100%	T1	Turbine No. 1	21.50	52.93	16.17	16.17
	T2	Turbine No. 2	21.50	52.93	16.17	16.17
	T3	Turbine No. 3	21.50	52.93	16.17	16.17
	T4	Turbine No. 4	21.50	52.93	16.17	16.17
80%	T1	Turbine No. 1	18.18	44.77	13.67	13.67
	T2	Turbine No. 2	18.18	44.77	13.67	13.67
	T3	Turbine No. 3	18.18	44.77	13.67	13.67
	T4	Turbine No. 4	18.18	44.77	13.67	13.67
70%	T1	Turbine No. 1	16.62	40.91	12.49	12.49
	T2	Turbine No. 2	16.62	40.91	12.49	12.49
	T3	Turbine No. 3	16.62	40.91	12.49	12.49
	T4	Turbine No. 4	16.62	40.91	12.49	12.49

Table D-4. Modeled Emission Rates for Turbines at 100%, 80%, and 70% Load - Fuel Oil

Load Case	Model ID	Description	Short-Term Emissions (lb/hr) CO	NO_x	PM_{10}	$PM_{2.5}$
100%	T1	Turbine No. 1	49.69	229.32	23.21	23.21
	T2	Turbine No. 2	49.69	229.32	23.21	23.21
	T3	Turbine No. 3	49.69	229.32	23.21	23.21
	T4	Turbine No. 4	49.69	229.32	23.21	23.21
80%	T1	Turbine No. 1	41.68	192.36	19.47	19.47
	T2	Turbine No. 2	41.68	192.36	19.47	19.47
	T3	Turbine No. 3	41.68	192.36	19.47	19.47
	T4	Turbine No. 4	41.68	192.36	19.47	19.47
70%	T1	Turbine No. 1	38.00	175.39	17.75	17.75
	T2	Turbine No. 2	38.00	175.39	17.75	17.75
	T3	Turbine No. 3	38.00	175.39	17.75	17.75
	T4	Turbine No. 4	38.00	175.39	17.75	17.75

Table D-5. Turbine Load Analysis Results - Natural Gas

Pollutant	Averaging Period	5-Year Average?[1]	Modeled Output	Load Analysis Modeled Conc. (μg/m³)[2] 100%	80%	70%
CO	1-hour	No	H1H	6.28586	7.90826	**9.12033**
	8-hour	No	H1H	3.08600	4.24872	**4.96050**
NO_2	1-hour	Yes	H1H	8.94047	14.24618	**15.27199**
	Annual	No	H1H	0.19998	**0.20035**	0.19899
PM_{10}	24-hour	No	H1H	0.93763	1.31603	**1.48877**
	Annual	No	H1H	**0.06796**	0.06789	0.06740
$PM_{2.5}$	24-hour	Yes	H1H	0.73491	0.77264	**0.77794**
	Annual	Yes	H1H	0.05882	**0.05912**	0.05882

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 has the same emission rates for PM_{10} and $PM_{2.5}$ and with individual years of meteorological data.

Table D-6. Turbine Load Analysis Results - Fuel Oil

Pollutant	Averaging Period	5-Year Average	Modeled Output	Load Analysis Modeled Conc. (μg/m³)[2] 100%	80%	70%
CO	1-hour	No	H1H	13.50292	**17.56151**	17.27463
	8-hour	No	H1H	6.61358	9.28964	**9.97696**
NO_2	1-hour	Yes	H1H	36.70302	58.33900	**59.04963**
	Annual	No	H1H	0.80933	**0.81510**	0.80997
PM_{10}	24-hour	No	H1H	1.24141	1.78516	**1.88917**
	Annual	No	H1H	0.09089	**0.09154**	0.09122
$PM_{2.5}$	24-hour	Yes	H1H	0.99162	1.01881	**1.05042**
	Annual	Yes	H1H	0.07860	**0.07969**	0.07956

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 has the same emission rates for PM_{10} and $PM_{2.5}$ and with individual years of meteorological data.

Table D-7. Production Data for Past Actual Emissions for Significance Modeling

		T1				T2				T3				T4			
Month	Year	Operating Time	NOx (tons)	CO (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	CO (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	CO (tons)	Heat Input (MMBtu)	Operating Time	NOx (tons)	CO (tons)	Heat Input (MMBtu)
1	2021	4	0.11	0.60	2,753.36	3	0.04	0.10	1,272.81	1	0.00	0.10	39.12	2	0.002	0.10	42.16
2	2021	--	--	--	--	5	0.07	0.10	3,690.68	2	0.076	0.20	1,247.19	--	--	--	--
3	2021	32	0.65	1.70	25,349.32	17	0.31	0.90	13,495.82	18	0.299	0.60	12,287.75	--	--	--	--
4	2021	39	0.62	0.70	37,909.25	48	0.69	0.60	46,404.48	48	0.767	0.70	45,136.01	66	1.12	1.40	63,734.56
5	2021	75	1.17	1.10	77,054.52	79	1.14	0.90	79,872.43	86	1.271	1.10	83,191.72	82	1.44	1.10	80,039.99
6	2021	153	2.08	1.80	149,509.01	151	2.02	1.50	143,657.95	144	1.913	1.30	133,999.73	132	2.06	2.20	124,267.50
7	2021	118	1.49	1.20	109,507.44	120	1.53	2.20	114,289.12	112	1.449	1.00	108,320.53	118	1.66	1.30	111,980.20
8	2021	113	1.61	1.60	103,992.32	122	1.86	1.60	113,052.73	115	1.587	1.30	103,060.94	110	1.60	1.90	100,067.47
9	2021	37	0.52	0.60	32,564.65	46	0.77	0.70	39,980.80	25	0.345	0.20	20,538.05	44	0.63	0.50	40,459.26
10	2021	3	0.04	0.10	1,079.02	3	0.03	--	1,133.40	94	1.368	0.80	86,267.65	105	1.53	1.20	96,350.26
11	2021	9	0.27	0.70	8,323.86	6	0.18	0.30	5,812.48	4	0.08	0.10	3,439.93	--	--	--	--
12	2021	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
1	2022	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
2	2022	--	--	--	--	--	--	--	--	1	0.002	0.10	39.95	1	0.00	0.10	38.34
3	2022	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
4	2022	4	0.07	0.24	3,701.20	--	--	--	--	21	0.412	0.29	19,326.76	7	0.11	0.11	5,723.24
5	2022	138	2.12	1.34	133,693.96	121	1.93	0.92	110,427.42	119	2.053	0.85	109,340.88	93	1.48	0.81	84,481.95
6	2022	248	3.54	1.86	243,319.50	237	3.69	1.92	236,095.19	271	4.435	1.54	262,429.35	229	3.60	1.36	226,158.60
7	2022	354	4.76	2.43	348,656.72	327	4.67	2.42	322,807.77	361	5.596	1.81	357,167.89	333	4.78	1.90	325,965.43
8	2022	313	4.14	2.72	306,069.86	318	4.77	2.54	310,980.22	316	4.931	1.96	308,974.04	309	4.48	1.90	299,806.88
9	2022	206	2.88	1.86	196,416.33	195	2.94	1.69	184,303.43	203	3.139	1.16	190,019.22	179	2.78	1.46	167,598.45
10	2022	2	0.05	0.10	1,677.55	--	--	--	--	16	0.284	0.14	13,044.60	14	0.26	0.20	12,240.39
11	2022	--	--	--	--	13	0.24	0.24	12,314.38	23	0.506	0.29	20,391.85	16	0.30	0.31	12,567.19
12	2022	--	--	--	--	32	0.62	0.68	25,751.68	53	1.16	0.75	49,240.26	51	1.16	1.02	50,213.25
	Sum	**1,848.00**	**26.10**	**20.66**	**1,781,578**	**1,843.00**	**27.47**	**19.32**	**1,765,343**	**2,033.00**	**31.68**	**16.27**	**1,927,503**	**1,891.00**	**29.01**	**18.87**	**1,801,735**

Table D-8. 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[1] (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	964.06	101.69	22.36	28.25	2.98	13.21	1.39	13.21	1.39
T2	957.86	100.76	20.96	29.81	3.14	13.12	1.38	13.12	1.38
T3	948.11	110.02	16.01	31.16	3.62	12.99	1.51	12.99	1.51
T4	952.79	102.84	19.96	30.68	3.31	13.05	1.41	13.05	1.41

1. Unless otherwise specified past actual emissions are based on actual heat input from January 2021 - December 2022. NO_x and CO emissions are based on actual emissions from January 2021 - December 2022 and actual hours of operation.
2. Based on actual heat input or NO_X emissions from January 2021 - December 2022 and potential 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

Table D-9. 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	2.82	3.56	0.38	1.66	0.18	1.66	0.18
T2	2.64	3.76	0.40	1.65	0.17	1.65	0.17
T3	2.02	3.93	0.46	1.64	0.19	1.64	0.19
T4	2.52	3.87	0.42	1.64	0.18	1.64	0.18

Table D-10. Significance Modeling Emission Rates - Natural Gas

EU	1-hr CO[1] (g/s)	8-hr CO[1] (g/s)	1-hr NO_x (g/s)	Annual 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)
Worst-Case Load Analysis								
T1	2.71	2.71	5.15	4.51	2.04	1.02	2.04	1.02
T2	2.71	2.71	5.15	4.51	2.04	1.02	2.04	1.02
T3	2.71	2.71	5.15	4.51	2.04	1.02	2.04	1.02
T4	2.71	2.71	5.15	4.51	2.04	1.02	2.04	1.02
Past Actuals								
T1	2.82	2.82	3.56	0.38	1.66	0.18	1.66	0.18
T2	2.64	2.64	3.76	0.40	1.65	0.17	1.65	0.17
T3	2.02	2.02	3.93	0.46	1.64	0.19	1.64	0.19
T4	2.52	2.52	3.87	0.42	1.64	0.18	1.64	0.18
Emission Rate								
T1	2.71	2.71	1.60	4.14	0.37	0.85	0.37	0.85
T2	2.71	2.71	1.40	4.12	0.38	0.85	0.38	0.85
T3	2.71	2.71	1.23	4.06	0.40	0.83	0.40	0.83
T4	2.71	2.71	1.29	4.09	0.39	0.84	0.39	0.84

1. Did not include past actual emissions for CO 1-hr or 8-hr for conservatism due to inclusion of SUSD in past actual CEMS data.

Table D-11. Significance Modeling Emission Rates - Fuel Oil

EU	1-hr CO (g/s)	8-hr CO (g/s)	1-hr NO_x (g/s)	Annual 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)
Worst-Case Load Analysis								
T1	5.25	4.79	22.10	4.51	2.24	1.02	2.24	1.02
T2	5.25	4.79	22.10	4.51	2.24	1.02	2.24	1.02
T3	5.25	4.79	22.10	4.51	2.24	1.02	2.24	1.02
T4	5.25	4.79	22.10	4.51	2.24	1.02	2.24	1.02
Past Actuals								
T1	2.82	2.82	3.56	0.38	1.66	0.18	1.66	0.18
T2	2.64	2.64	3.76	0.40	1.65	0.17	1.65	0.17
T3	2.02	2.02	3.93	0.46	1.64	0.19	1.64	0.19
T4	2.52	2.52	3.87	0.42	1.64	0.18	1.64	0.18
Emission Rate								
T1	2.43	1.97	18.54	4.14	0.57	0.85	0.57	0.85
T2	2.61	2.15	18.34	4.12	0.58	0.85	0.58	0.85
T3	3.23	2.77	18.17	4.06	0.60	0.83	0.60	0.83
T4	2.74	2.27	18.23	4.09	0.59	0.84	0.59	0.84

Table D-12. Turbines 1-4 Startup/Shutdown Emissions for Significance Modeling

	Natural Gas			Fuel Oil		
EU	1-hr CO (g/s)	8-hr CO (g/s)	1-hr NO_x (g/s)	1-hr CO (g/s)	8-hr CO (g/s)	1-hr NO_x (g/s)
Startup						
T1B	34.78	34.78	9.32	64.76	64.76	30.74
T2B	34.78	34.78	9.32	64.76	64.76	30.74
T3B	34.78	34.78	9.32	64.76	64.76	30.74
T4B	34.78	34.78	9.32	64.76	64.76	30.74
Shutdown						
T1C	10.33	10.33	9.58	39.56	39.56	36.04
T2C	10.33	10.33	9.58	39.56	39.56	36.04
T3C	10.33	10.33	9.58	39.56	39.56	36.04
T4C	10.33	10.33	9.58	39.56	39.56	36.04

Table D-13. Class II SIL Results

Pollutant	Averaging Period	5-Year Average	Model Output	Scenario	Natural Gas Operation[1] 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?	Radius of SIA (km)	Fuel Oil Operation[1] 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?	Radius of SIA (km)
PM$_{2.5}$ [2]	24-hour	Yes	H1H	Normal	0.19	0.12	0.31	1.2	No	N/A	0.24	0.12	0.36	1.2	No	N/A
	Annual	Yes	H1H	Normal	0.03	5.27E-03	0.03	0.2	No	N/A	0.03	5.27E-03	0.03	0.2	No	N/A
PM$_{10}$	24-hour	Yes	H1H	Normal	0.36	--	--	5	No	N/A	0.37	--	--	5	No	N/A
	Annual	No	H1H	Normal	0.03	--	--	1	No	N/A	0.03	--	--	1	No	N/A
CO	1-hour	Yes	H1H	Normal	11.83	--	--	2,000	No	N/A	8.44	--	--	2,000	No	N/A
				4 am Startup	31.95	--	--	2,000	No	N/A	73.50	--	--	2,000	No	N/A
				10 am Startup	118.51	--	--	2,000	No	N/A	213.65	--	--	2,000	No	N/A
	8-hour	Yes	H1H	Normal	6.43	--	--	500	No	N/A	3.81	--	--	500	No	N/A
				4 am Startup	6.45	--	--	500	No	N/A	9.26	--	--	500	No	N/A
				10 am Startup	23.08	--	--	500	No	N/A	43.54	--	--	500	No	N/A
NO$_2$ [3]	1-hour	Yes	H1H	Normal	4.16	--	--	7.5	No	N/A	48.24	--	--	7.5	Yes	49.8
				4 am Startup	12.58	--	--	7.5	Yes	41.8	48.24	--	--	7.5	Yes	50
				10 am Startup	14.00	--	--	7.5	Yes	9.3	53.79	--	--	7.5	Yes	49.8
	Annual	No	H1H	Normal	0.15	--	--	1	No	N/A	0.14	--	--	1	No	N/A

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 3,750 hours per year, and fuel oil operation is expected for 450 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).

Table D-14. Class I SIL Analysis

Pollutant	Averaging Period	5-Year Average	Model Output	Natural Gas Operation[1] 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?	Fuel Oil Operation[1] 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$_{2.5}$	24-hr	Yes	H1H	0.025	9.06E-02	0.12	0.27	No	0.034	0.09	0.12	0.27	No
	Annual	Yes	H1H	4.30E-03	2.36E-03	6.66E-03	0.05	No	4.16E-03	2.36E-03	6.52E-03	0.05	No
PM$_{10}$	24-hr	Yes	H1H	0.035	--	--	0.3	No	0.046	--	--	0.3	No
	Annual	No	H1H	4.43E-03	--	--	0.2	No	4.61E-03	--	--	0.2	No
NO$_2$	Annual	No	H1H	0.021	--	--	0.1	No	0.022	--	--	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 3,750 hours per year, and fuel oil operation is expected for 450 hours per year.

Table D-15. 1hr-NO_2 Natural Gas 4am/10am SUSD AERMOD Inputs

ID	Description	x-coord (m)	y-coord (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
T1	Turbine No.1	716647.8	3608142.4	157.38	5.15	27.43	814.26	27.36	5.61
T2	Turbine No. 2	716647.8	3608111.7	157.47	5.15	27.43	814.26	27.36	5.61
T3	Turbine No. 3	716647.8	3608083.6	157.54	5.15	27.43	814.26	27.36	5.61
T4	Turbine No. 4	716647.8	3608054.7	157.51	5.15	27.43	814.26	27.36	5.61
T5	Turbine No. 5	716647.8	3608024.8	157.48	5.15	27.43	814.26	27.36	5.61
T6	Turbine No. 6	716647.8	3607996.3	157.56	5.15	27.43	814.26	27.36	5.61
PHTR1	NG Preheater 1	716704.5	3608146.5	157.32	0.084	3.96	682.59	17.80	0.34
PHTR2	NG Preheater 2	716706.1	3608088.4	157.32	0.084	3.96	682.59	17.80	0.34
PHTR3	NG Preheater 3	716706.8	3608030.5	157.31	0.084	3.96	682.59	17.80	0.34
T1A	T1 Startup	716647.8	3608142.4	157.38	9.32	27.43	729.26	26.52	5.61
T2A	T2 Startup	716647.8	3608111.7	157.47	9.32	27.43	729.26	26.52	5.61
T3A	T3 Startup	716647.8	3608083.6	157.54	9.32	27.43	729.26	26.52	5.61
T4A	T4 Startup	716647.8	3608054.7	157.51	9.32	27.43	729.26	26.52	5.61
T5A	T5 Startup	716647.8	3608024.8	157.48	9.32	27.43	729.26	26.52	5.61
T6A	T6 Startup	716647.8	3607996.3	157.56	9.32	27.43	729.26	26.52	5.61
T1B	T1 Shutdown	716647.8	3608142.4	157.38	9.58	27.43	788.15	30.26	5.61
T2B	T2 Shutdown	716647.8	3608111.7	157.47	9.58	27.43	788.15	30.26	5.61
T3B	T3 Shutdown	716647.8	3608083.6	157.54	9.58	27.43	788.15	30.26	5.61
T4B	T4 Shutdown	716647.8	3608054.7	157.51	9.58	27.43	788.15	30.26	5.61
T5B	T5 Shutdown	716647.8	3608024.8	157.48	9.58	27.43	788.15	30.26	5.61
T6B	T6 Shutdown	716647.8	3607996.3	157.56	9.58	27.43	788.15	30.26	5.61

Table D-16. 1hr-NO_2 Fuel Oil Normal Operation AERMOD Inputs

ID	Description	x-coord (m)	y-coord (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
T1	Turbine No.1	716647.8	3608142.4	157.38	22.10	27.43	815.37	28.55	5.61
T2	Turbine No. 2	716647.8	3608111.7	157.47	22.10	27.43	815.37	28.55	5.61
T3	Turbine No. 3	716647.8	3608083.6	157.54	22.10	27.43	815.37	28.55	5.61
T4	Turbine No. 4	716647.8	3608054.7	157.51	22.10	27.43	815.37	28.55	5.61
T5	Turbine No. 5	716647.8	3608024.8	157.48	22.10	27.43	815.37	28.55	5.61
T6	Turbine No. 6	716647.8	3607996.3	157.56	22.10	27.43	815.37	28.55	5.61
PHTR1	NG Preheater 1	716704.524	3608146.544	157.32	0.084	3.96	682.59	17.80	0.34
PHTR2	NG Preheater 2	716706.068	3608088.434	157.32	0.084	3.96	682.59	17.80	0.34
PHTR3	NG Preheater 3	716706.841	3608030.516	157.31	0.084	3.96	682.59	17.80	0.34

Table D-17. 1hr-NO_2 Fuel Oil 4am/10am SUSD AERMOD Inputs

ID	Description	x-coord (m)	y-coord (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
T1	Turbine No.1	716647.8	3608142.4	157.38	22.1	27.43	815.37	28.55	5.61
T2	Turbine No. 2	716647.8	3608111.7	157.47	22.1	27.43	815.37	28.55	5.61
T3	Turbine No. 3	716647.8	3608083.6	157.54	22.1	27.43	815.37	28.55	5.61
T4	Turbine No. 4	716647.8	3608054.7	157.51	22.1	27.43	815.37	28.55	5.61
T5	Turbine No. 5	716647.8	3608024.8	157.48	22.1	27.43	815.37	28.55	5.61
T6	Turbine No. 6	716647.8	3607996.3	157.56	22.1	27.43	815.37	28.55	5.61
PHTR1	NG Preheater 1	716704.5	3608146.5	157.32	0.084	3.96	682.59	17.80	0.34
PHTR2	NG Preheater 2	716706.1	3608088.4	157.32	0.084	3.96	682.59	17.80	0.34
PHTR3	NG Preheater 3	716706.8	3608030.5	157.31	0.084	3.96	682.59	17.80	0.34
T1A	T1 Startup	716647.8	3608142.4	157.38	30.74	27.43	729.26	27.28	5.61
T2A	T2 Startup	716647.8	3608111.7	157.47	30.74	27.43	729.26	27.28	5.61
T3A	T3 Startup	716647.8	3608083.6	157.54	30.74	27.43	729.26	27.28	5.61
T4A	T4 Startup	716647.8	3608054.7	157.51	30.74	27.43	729.26	27.28	5.61
T5A	T5 Startup	716647.8	3608024.8	157.48	30.74	27.43	729.26	27.28	5.61
T6A	T6 Startup	716647.8	3607996.3	157.56	30.74	27.43	729.26	27.28	5.61
T1B	T1 Shutdown	716647.8	3608142.4	157.38	36.04	27.43	787.59	31.33	5.61
T2B	T2 Shutdown	716647.8	3608111.7	157.47	36.04	27.43	787.59	31.33	5.61
T3B	T3 Shutdown	716647.8	3608083.6	157.54	36.04	27.43	787.59	31.33	5.61
T4B	T4 Shutdown	716647.8	3608054.7	157.51	36.04	27.43	787.59	31.33	5.61
T5B	T5 Shutdown	716647.8	3608024.8	157.48	36.04	27.43	787.59	31.33	5.61
T6B	T6 Shutdown	716647.8	3607996.3	157.56	36.04	27.43	787.59	31.33	5.61

Table D-18. 1hr-NO_2 NAAQS Results Summary

Pollutant	Averaging Period	5-Year Average	Model Output	Fuel Type	Scenario	Modeled Conc. (μg/m³)	Background Conc. (μg/m³)	Total NO_2 Impact (μg/m³)	NAAQS (μg/m³)	Exceeds NAAQS?
NO_2	1-hour	Yes	H8H	Natural Gas	4 am Startup	137.33	30.3	167.63	188	No
					10 am Startup	100.37	30.3	130.67	188	No
				Fuel Oil	Normal	1,540.43	30.3	1,570.73	188	Yes
					4 am Startup	1,540.43	30.3	1,570.73	188	Yes
					10 am Startup	1,540.43	30.3	1,570.73	188	Yes

Table D-19. 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)	Notes / Exclusion Reason
1	SOUTHERN NATURAL GAS CO.	14500002	11480 Warm Springs Rd	Ellerslie	35202	Harris	4922	16	704390.2	3610296.8	704390.2	3610296.8	12.41	No	--
2	Fall Line Quarry, LLC	14500004	225 Grey Rock Rd.	Midland	31820	Harris	1423	16	696595.9	3608554.5	696595.9	3608554.5	20.00	No	--
3	Koch Foods of Pine Mountain Valley, LLC	14500010	14075 Highway 116	Pine mountain Valley	31823	Harris	2015	16	703842.6	3631028.2	703842.6	3631028.2	26.32	No	--
4	Oakcrest Lumber Inc	19700010	3287 State Highway 41	Buena Vista	31803	Marion	2421	16	733694.9	3578656.2	733694.9	3578656.2	33.97	No	--
5	Georgia-Pacific Wood Products LLC (Warm Springs Plywood Plant)	19900004	5875 Chipley Hwy	Warm Springs	31830	Meriwether	2436	16	708293.0	3644376.7	708293.0	3644376.7	37.31	No	--
6	Aludyne Columbus, LLC.	21500001	1600 Northside Industrial Blvd	Columbus	31914	Muscogee	3321	16	690660.0	3601037.2	690825.3	3600815.2	26.75	No	--
7	Goldens' Foundry & Machine Co	21500002	600 Twelfth Street	Columbus	31902	Muscogee	3321	16	689412.5	3594152.1	689412.5	3594152.1	30.50	No	--
8	United Technologies Corp. - Pratt and Whitney	21500013	8801 Macon Rd	Columbus	31908	Muscogee	3724	16	694196.2	3596364.1	702328.5	3601068.8	15.86	No	Facility shows up as Pratt & Whitney in Google Earth
9	S-L Snacks GA, LLC	21500017	900 8th Street	Columbus	31901	Muscogee	2068	16	689798.6	3592973.1	689798.6	3592973.1	30.72	No	--
10	United States Army Maneuver Center of Excellence - Fort Benning	21500021	Fort Benning	Ft. Benning	31905	Muscogee	9711	16	692579.5	3583202.1	692579.5	3583202.1	34.52	No	--
11	Wilana Chemical, LLC	21500023	1136 Chumar Street	Columbus	31904	Muscogee	2843	16	690308.1	3599770.5	690373.7	3599703.6	27.50	No	--
12	HPPE, LLC	21500024	6906 Dixie Street	Columbus	31907	Muscogee	2836	16	699857.1	3599202.3	699857.1	3599202.3	18.91	No	
13	Kemira Chemicals Inc	21500032	6601 Canal Street	Columbus	31907	Muscogee	2821	16	699347.8	3598792.8	699614.7	3598910.0	19.26	No	--
14	ABX Solutions LLC	21500035	918 8th Avenue	Columbus	31902	Muscogee	2751	16	689659.7	3593574.0	689702.1	3593651.5	30.48	No	--
15	Vulcan Construction Materials, LLC - Barin Quarry	21500037	9205 Fortson Rd.	Fortson	31808	Muscogee	1423	16	692478.9	3605091.7	692335.4	3607389.8	24.26	No	--
16	Exide Technologies	21500051	3639 Joy Road	Columbus	31902	Muscogee	3341	16	694251.7	3590681.2	694485.8	3590667.3	28.09	No	--
17	MPLX Terminals, LLC - Columbus Terminal	21500080	5030 Miller Road	Columbus	31908	Muscogee	5171	16	696596.8	3600291.4	696507.6	3600215.3	21.54	No	--
18	Hostess Brands, LLC	21500102	1969 Victory Dr	Columbus	31902	Muscogee	2051	16	690852.3	3591400.4	690962.2	3591512.6	30.47	No	--
19	Robinson Paving Company - Asphalt Division Plant 1	21500116	3015 Smith Rd	Fortson	31808	Muscogee	2951	16	692869.8	3608061.4	692869.8	3608061.4	23.72	No	Renamed from Southern Asphalt to Robinson Paving
20	Tremco CPG Inc.	21500130	4827 Milgen Road	Columbus	31907	Muscogee	3299	16	696220.4	3599653.3	696340.2	3599874.6	21.82	No	Renamed from Dryvit Systems to Tremco
21	ARGOS Ready Mix LLC.	21500139	5526 Schatulga Road	Columbus	31907	Muscogee	3273	16			700370.8	3600185.3	18.00	No	--
22	Kysor / Warren (Warren Sherer)	21500143	5201 Transport Blvd.	Columbus	31907	Muscogee	2542	16	699901.6	3599564.9	699901.6	3599564.9	18.70	No	--
23	St. Francis Health, LLC d/b/a St. Francis Hospital	21500146	2122 Manchester Expy	Columbus	31904	Muscogee	8062	16	691529.6	3598440.6	691627.2	3598337.9	26.77	No	--
24	Eastman Kodak Company	21500148	One Kodak Way	Columbus	31907	Muscogee	3479	16	698607.0	3597386.1	699489.7	3598454.1	19.59	No	--
25	Omega Partners Columbus LLC	21500149	5225 Miller Road	Columbus	31909	Muscogee	5171	16	696896.9	3600314.1	696922.5	3600338.3	21.11	No	--
26	The Medical Center Inc.	21500150	710 Center Street	Columbus	31901	Muscogee	8062	16	689532.0	3595577.8	689674.7	3595484.5	29.68	No	--
27	Stepan Company	21500153	1 Polymer Way	Columbus	31907	Muscogee	2821	16	699341.9	3600083.6	699005.9	3598684.3	19.90	No	--
28	International Paper Company	21500154	4847 Cargo Drive	Columbus	31907	Muscogee	2653	16	699238.6	3599059.6	698973.1	3599307.0	19.65	No	--
29	Panasonic Battery Corp of America	21500158	One Panasonic Dr	Columbus	31907	Muscogee	3411	16			699203.2	3597557.1	20.28	No	--
30	Panasonic Energy	21500161	One Panasonic Dr	Columbus	31907	Muscogee	3411	16	699862.8	3598193.8	699203.2	3597557.1	20.28	No	--
31	Matthews CW Contracting Co Inc. Plt 66	21500163	2930 Smith Road	Fortson	31808	Muscogee	2951	16			692449.2	3608164.1	24.14	No	--
32	Panasonic Battery Corporation of America - Lithium Division	21500164	One Panasonic Dr	Columbus	31907	Muscogee	3692	16			699203.2	3597557.1	20.28	No	--
33	Denim North America, LLC	21500176	1 Marubeni Drive	Columbus	31907	Muscogee	2269	16			698778.9	3598074.6	20.39	No	--
34	Columbus Quarry, LLC	21500179	3001 Smith Rd.	Fortson	31808	Muscogee	1423	16	689132.2	3593302.4	692907.4	3608310.2	23.69	No	--
35	Pine Grove Landfill	21500181	7900 Pine Grove Way	Columbus	31907	Muscogee	4953	16	700576.1	3597592.7	701787.7	3596459.1	18.77	No	--
36	ICForm Inc	21500183	4551 Cargo Drive	Columbus	31907	Muscogee	3086	16	699640.4	3598556.6	699677.7	3598387.8	19.45	No	--
37	Sherman Industries, Inc.	21500185	3015 Smith Rd	Fortson	31808	Muscogee	3273	16	692953.9	3608048.8	692789.1	3607916.0	23.80	No	--
38	Ready Mix USA, LLC - Smith Road Plant	21500188	3030 Smith Road	Columbus	31908	Muscogee	3273	16			692789.1	3607916.0	23.80	No	--
39	Ready Mix USA, LLC - Andrews Road Plant	21500189	532 Andrews Road	Columbus	31902	Muscogee	3273	16			693001.6	3592380.5	28.29	No	--
40	South Columbus Water Resource Facility	21500190	3001 South Lumpkin Road	Columbus	31902	Muscogee	4952	16	692264.3	3586841.2	690238.0	3587793.9	33.21	No	--
41	JPS Technology, INC.	21500192	4530 Cargo Drive	Columbus	31907	Muscogee	2261	16			699707.7	3598666.1	19.29	No	--
42	North Columbus Water Resources Facility	21500202	5301 River Road	Columbus	31902	Muscogee	4941	16			688931.8	3599611.9	28.90	No	--
43	Kysor Warren EPTA US Corporation	21500206	5 Corporate Ridge	Columbus	31907	Muscogee	3585	16			699314.2	3597208.4	20.37	No	--
44	Columbus Power Producers, LLC	21500208	7900 Pine Grove Way	Columbus	31907	Muscogee	1311	16			701787.7	3596459.1	18.77	No	Facility is on the same property as the Pine Grove Landfill
45	Martin Marietta Aggregates	26300009	GA Hwy 90	Junction City	31812	Talbot	1423	16	736368.0	3612154.0	735790.7	3611837.2	19.58	No	--
46	Junction City Mining Company	26300012	2158 Packing House Rd	Talbotton	31827	Talbot	1423	16	730723.2	3618325.9	733861.3	3614194.7	18.35	No	--
47	WI TAYLOR COUNTY DISPOSAL, LLC	26900014	33 Stewart Road	Mauk	31058	Taylor	4953	16	745695.6	3593201.4	745695.6	3593201.4	32.65	No	--
48	MF & H Textiles Inc	26900017	P.O. Box 1970	Butler	31006	Taylor	2261	16	759329.8	3605560.5	757308.9	3606489.8	40.75	No	--
49	Milliken & Company Pine Mountain Plant	28500093	7495 Hamilton Road	Pine Mountain	31822	Troup	2221	16	696567.3	3642226.8	696923.3	3642437.5	39.66	No	--
50	TenCate Protective Fabrics	29300024	1683 Lawrence Rd	Molena	30258	Upson	2262	16	734571.0	3650886.8	734447.8	3650453.1	46.05	No	--
51	SOUTHERN NATURAL GAS CO.	29300025	5276 Hwy 19 South	Thomaston	30286	Upson	4922	16	757136.0	3631089.6	757143.4	3631098.0	46.67	No	--
52	Lancaster Energy Partners - Thomaston	29300029	35 Edgewood Avenue	Thomaston	30286	Upson	4911	16	751153.1	3643359.0	751290.8	3643517.2	49.65	No	--
53	Apollo Technologies, Animal Health and Sciences, Inc. - Thomaston Plan	29300036	100 Chris Callas Parkway	Thomaston	30286	Upson	2899	16	750091.3	3642061.2	752350.6	3641189.5	48.79	No	--

Table D-20. 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)	NO_X Emissions (lb/hr)	NO_X Emissions (tpy)	$PM_{2.5}$ Emissions (lb/hr)	$PM_{2.5}$ Emissions (tpy)	Reference of Emission Rates
1	SOUTHERN NATURAL GAS CO.	A	14500002	11480 Warm Springs Rd	Ellerslie	35202	Harris	704390.2	3610296.8	12.41	N/A	1,208.00	N/A	29.00	https://psd.gaepd.org/inventory/
2	Fall Line Quarry, LLC	SM	14500004	225 Grey Rock Rd.	Midland	31820	Harris	696595.9	3608554.5	20.00	N/A	--	N/A	46.00	https://psd.gaepd.org/inventory/
3	Koch Foods of Pine Mountain Valley, LLC	B	14500010	14075 Highway 116	Pine mountain Valley	31823	Harris	703842.6	3631028.2	26.32	N/A	100.00	N/A	100.00	See Note 1
4	Oakcrest Lumber Inc	B	19700010	3287 State Highway 41	Buena Vista	31803	Marion	733694.9	3578656.2	33.97	N/A	100.00	N/A	100.00	See Note 1
5	Georgia-Pacific Wood Products LLC (Warm Springs Plywood Plant)	B	19900004	5875 Chipley Hwy	Warm Springs	31830	Meriwether	708293.0	3644376.7	37.31	N/A	100.00	N/A	100.00	See Note 1
6	Aludyne Columbus, LLC.	A	21500001	1600 Northside Industrial Blvd	Columbus	31914	Muscogee	690825.3	3600815.2	26.75	N/A	12.00	N/A	40.00	https://psd.gaepd.org/inventory/
7	Goldens' Foundry & Machine Co	SM	21500002	600 Twelfth Street	Columbus	31902	Muscogee	689412.5	3594152.1	30.50	N/A	--	N/A	74.00	https://psd.gaepd.org/inventory/
8	United Technologies Corp. - Pratt and Whitney	A	21500013	8801 Macon Rd	Columbus	31908	Muscogee	702328.5	3601068.8	15.86	N/A	155.00	N/A	--	https://psd.gaepd.org/inventory/
9	S-L Snacks GA, LLC	B	21500017	900 8th Street	Columbus	31901	Muscogee	689798.6	3592973.1	30.72	N/A	28.60	N/A	2.20	https://permitsearch.gaepd.org/
10	United States Army Maneuver Center of Excellence - Fort Benning	A	21500021	Fort Benning	Ft. Benning	31905	Muscogee	692579.5	3583202.1	34.52	N/A	703.00	N/A	49.00	https://psd.gaepd.org/inventory/
11	Wilana Chemical, LLC	SM	21500023	1136 Chumar Street	Columbus	31904	Muscogee	690373.7	3599703.6	27.50	N/A	5.13	N/A	8.20	https://permitsearch.gaepd.org/
12	HPPE, LLC	B	21500024	6906 Dixie Street	Columbus	31907	Muscogee	699857.1	3599202.3	18.91	N/A	26.58	N/A	0.51	https://permitsearch.gaepd.org/
13	Kemira Chemicals Inc	B	21500032	6601 Canal Street	Columbus	31907	Muscogee	699614.7	3598910.0	19.26	N/A	14.00	N/A	1.90	https://permitsearch.gaepd.org/
14	ABX Solutions LLC	SM	21500035	918 8th Avenue	Columbus	31902	Muscogee	689702.1	3593651.5	30.48	N/A	100.00	N/A	100.00	See Note 1
15	Vulcan Construction Materials, LLC - Barin Quarry	SM	21500037	9205 Fortson Rd.	Fortson	31808	Muscogee	692335.4	3607389.8	24.26	N/A	100.00	N/A	100.00	See Note 1
16	Exide Technologies	SM	21500051	3639 Joy Road	Columbus	31902	Muscogee	694485.8	3590667.3	28.09	N/A	23.00	N/A	40.00	https://psd.gaepd.org/inventory/
17	MPLX Terminals, LLC - Columbus Terminal	SM	21500080	5030 Miller Road	Columbus	31908	Muscogee	696507.6	3600215.3	21.54	N/A	--	N/A	--	Not a source of NO_X or $PM_{2.5}$ emissions.
18	Hostess Brands, LLC	B	21500102	1969 Victory Dr	Columbus	31902	Muscogee	690962.2	3591512.6	30.47	N/A	100.00	N/A	100.00	See Note 1
19	Robinson Paving Company - Asphalt Division Plant 1	SM	21500116	3015 Smith Rd	Fortson	31808	Muscogee	692869.8	3608061.4	23.72	N/A	14.00	N/A	14.00	https://psd.gaepd.org/inventory/
20	Tremco CPG Inc.	B	21500130	4827 Milgen Road	Columbus	31907	Muscogee	696340.2	3599874.6	21.82	N/A	100.00	N/A	100.00	See Note 1
21	ARGOS Ready Mix LLC.	B	21500139	5526 Schatulga Road	Columbus	31907	Muscogee	700370.8	3600185.3	18.00	N/A	100.00	N/A	100.00	See Note 1
22	Kysor / Warren (Warren Sherer)	SM	21500143	5201 Transport Blvd.	Columbus	31907	Muscogee	699901.6	3599564.9	18.70	N/A	--	N/A	--	Not a source of NO_X or $PM_{2.5}$ emissions.
23	St. Francis Health, LLC d/b/a St. Francis Hospital	SM	21500146	2122 Manchester Expy	Columbus	31904	Muscogee	691627.2	3598337.9	26.77	N/A	7.00	N/A	1.00	https://psd.gaepd.org/inventory/
24	Eastman Kodak Company	SM	21500148	One Kodak Way	Columbus	31907	Muscogee	699489.7	3598454.1	19.59	N/A	100.00	N/A	100.00	See Note 1
25	Omega Partners Columbus LLC	SM	21500149	5225 Miller Road	Columbus	31909	Muscogee	696922.5	3600338.3	21.11	N/A	--	N/A	--	Not a source of NO_X or $PM_{2.5}$ emissions.
26	The Medical Center Inc.	B	21500150	710 Center Street	Columbus	31901	Muscogee	689674.7	3595484.5	29.68	N/A	36.00	N/A	0.50	https://permitsearch.gaepd.org/
27	Stepan Company	B	21500153	1 Polymer Way	Columbus	31907	Muscogee	699005.9	3598684.3	19.90	N/A	41.30	N/A	27.80	https://permitsearch.gaepd.org/
28	International Paper Company	SM	21500154	4847 Cargo Drive	Columbus	31907	Muscogee	698973.1	3599307.0	19.65	N/A	10.00	N/A	1.00	https://psd.gaepd.org/inventory/
29	Panasonic Battery Corp of America	A	21500158	One Panasonic Dr	Columbus	31907	Muscogee	699203.2	3597557.1	20.28	N/A	3.00	N/A	17.70	https://permitsearch.gaepd.org/
30	Panasonic Energy	SM	21500161	One Panasonic Dr	Columbus	31907	Muscogee	699203.2	3597557.1	20.28	N/A	--	N/A	0.80	https://permitsearch.gaepd.org/
31	Matthews CW Contracting Co Inc. Plt 66	SM	21500163	2930 Smith Road	Fortson	31808	Muscogee	692449.2	3608164.1	24.14	N/A	16.00	N/A	56.00	https://psd.gaepd.org/inventory/
32	Panasonic Battery Corporation of America - Lithium Division	A	21500164	One Panasonic Dr	Columbus	31907	Muscogee	699203.2	3597557.1	20.28	N/A	100.00	N/A	100.00	See Note 1
33	Denim North America, LLC	B	21500176	1 Marubeni Drive	Columbus	31907	Muscogee	698778.9	3598074.6	20.39	N/A	100.00	N/A	100.00	See Note 1
34	Columbus Quarry, LLC	SM	21500179	3001 Smith Rd.	Fortson	31808	Muscogee	692907.4	3608310.2	23.69	N/A	--	N/A	20.00	https://psd.gaepd.org/inventory/
35	Pine Grove Landfill	A	21500181	7900 Pine Grove Way	Columbus	31907	Muscogee	701787.7	3596459.1	18.77	N/A	100.00	N/A	100.00	See Note 1
36	ICForm Inc	SM	21500183	4551 Cargo Drive	Columbus	31907	Muscogee	699677.7	3598387.8	19.45	N/A	3.34	N/A	2.68	https://permitsearch.gaepd.org/
37	Sherman Industries, Inc.	PBR	21500185	3015 Smith Rd	Fortson	31808	Muscogee	692789.1	3607916.0	23.80	N/A	--	N/A	--	See Note 2
38	Ready Mix USA, LLC - Smith Road Plant	PBR	21500188	3030 Smith Road	Columbus	31908	Muscogee	692789.1	3607916.0	23.80	N/A	--	N/A	--	See Note 2
39	Ready Mix USA, LLC - Andrews Road Plant	PBR	21500189	532 Andrews Road	Columbus	31902	Muscogee	693001.6	3592380.5	28.29	N/A	--	N/A	--	See Note 2
40	South Columbus Water Resource Facility	SM	21500190	3001 South Lumpkin Road	Columbus	31902	Muscogee	690238.0	3587793.9	33.21	N/A	49.00	N/A	1.00	https://psd.gaepd.org/inventory/
41	JPS Technology, INC.	B	21500192	4530 Cargo Drive	Columbus	31907	Muscogee	699707.7	3598666.1	19.29	N/A	3.70	N/A	0.28	https://permitsearch.gaepd.org/
42	North Columbus Water Resources Facility	PBR	21500202	5301 River Road	Columbus	31902	Muscogee	688931.8	3599611.9	28.90	N/A	--	N/A	--	See Note 2
43	Kysor Warren EPTA US Corporation	PBR	21500206	5 Corporate Ridge	Columbus	31907	Muscogee	699314.2	3597208.4	20.37	N/A	--	N/A	--	See Note 2
44	Columbus Power Producers, LLC	B	21500208	7900 Pine Grove Way	Columbus	31907	Muscogee	701787.7	3596459.1	18.77	N/A	1.22	N/A	0.52	https://permitsearch.gaepd.org/
45	Martin Marietta Aggregates	SM	26300009	GA Hwy 90	Junction City	31812	Talbot	735790.7	3611837.2	19.58	N/A	--	N/A	31.00	https://psd.gaepd.org/inventory/
46	Junction City Mining Company	SM	26300012	2158 Packing House Rd	Talbotton	31827	Talbot	733861.3	3614194.7	18.35	N/A	57.00	N/A	98.00	https://psd.gaepd.org/inventory/
47	WI TAYLOR COUNTY DISPOSAL, LLC	A	26900014	33 Stewart Road	Mauk	31058	Taylor	745695.6	3593201.4	32.65	N/A	13.00	N/A	5.00	https://psd.gaepd.org/inventory/
48	MF & H Textiles Inc	B	26900017	P.O. Box 1970	Butler	31006	Taylor	757308.9	3606489.8	40.75	N/A	100.00	N/A	100.00	See Note 1
49	Milliken & Company Pine Mountain Plant	B	28500093	7495 Hamilton Road	Pine Mountain	31822	Troup	696923.3	3642437.5	39.66	N/A	100.00	N/A	100.00	See Note 1
50	TenCate Protective Fabrics	A	29300024	1683 Lawrence Rd	Molena	30258	Upson	734447.8	3650453.1	46.05	N/A	49.00	N/A	7.00	https://psd.gaepd.org/inventory/
51	SOUTHERN NATURAL GAS CO. - 1	A	29300025	5276 Hwy 19 South	Thomaston	30286	Upson	757143.4	3631098.0	46.67	N/A	3.61	N/A	0.01	https://permitsearch.gaepd.org/
52	Lancaster Energy Partners - Thomaston	A	29300029	35 Edgewood Avenue	Thomaston	30286	Upson	751290.8	3643517.2	49.65	N/A	235.00	N/A	44.00	https://psd.gaepd.org/inventory/
53	Apollo Technologies, Animal Health and Sciences, Inc. - Thomaston Plan	B	29300036	100 Chris Callas Parkway	Thomaston	30286	Upson	752350.6	3641189.5	48.79	N/A	100	N/A	100	See Note 1

1. No data available, PTE is conservatively assumed based on minor source status
2. Permit-By-Rule Source; exclude from source cluster matrix.

Table D-21. NO_2 Regional Source Inventory - File Review Sources

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 Inventory Source?	File Review Source?	Notes
14500002	SOUTHERN NATURAL GAS CO.	Ellerslie	Harris	A	17	704390	3610297	12.4	1208.00	Yes	No	Title V Source; Do not include in file review.
14500010	Koch Foods of Pine Mountain Valley, LLC	Pine mountain Valley	Harris	B	19	703843	3631028	26.3	100.00	Yes	Yes	File review necessary to confirm sources.
19700010	Oakcrest Lumber Inc	Buena Vista	Marion	B	20	733695	3578656	34.0	100.00	Yes	Yes	See Note 1
19900004	Georgia-Pacific Wood Products LLC (Warm Springs Plywood Plant)	Warm Springs	Meriwether	B	21	708293	3644377	37.3	100.00	Yes	Yes	See Note 1
21500001	Aludyne Columbus, LLC.	Columbus	Muscogee	A	22	690825	3600815	26.7	12.00	Yes	No	Title V Source; Do not include in file review.
21500013	United Technologies Corp. - Pratt and Whitney	Columbus	Muscogee	A	24	702328	3601069	15.9	155.00	Yes	No	Title V Source; Do not include in file review.
21500017	S-L Snacks GA, LLC	Columbus	Muscogee	B	25	689799	3592973	30.7	28.60	Yes	Yes	See Note 1
21500021	United States Army Maneuver Center of Excellence - Fort Benning	Ft. Benning	Muscogee	A	26	692580	3583202	34.5	703.00	Yes	No	Title V Source; Do not include in file review.
21500023	Wilana Chemical, LLC	Columbus	Muscogee	SM	27	690374	3599704	27.5	5.13	Yes	Yes	See Note 1
21500024	HPPE, LLC	Columbus	Muscogee	B	28	699857	3599202	18.9	26.58	Yes	Yes	See Note 1
21500032	Kemira Chemicals Inc	Columbus	Muscogee	B	29	699615	3598910	19.3	14.00	Yes	Yes	See Note 1
21500035	ABX Solutions LLC	Columbus	Muscogee	SM	30	689702	3593652	30.5	100.00	Yes	Yes	See Note 1
21500037	Vulcan Construction Materials, LLC - Barin Quarry	Fortson	Muscogee	SM	31	692335	3607390	24.3	100.00	Yes	Yes	See Note 1
21500051	Exide Technologies	Columbus	Muscogee	SM	32	694486	3590667	28.1	23.00	Yes	Yes	See Note 1
21500102	Hostess Brands, LLC	Columbus	Muscogee	B	34	690962	3591513	30.5	100.00	Yes	Yes	See Note 1
21500116	Robinson Paving Company - Asphalt Division Plant 1	Fortson	Muscogee	SM	35	692870	3608061	23.7	14.00	Yes	Yes	See Note 1
21500130	Tremco CPG Inc.	Columbus	Muscogee	B	36	696340	3599875	21.8	100.00	Yes	Yes	See Note 1
21500139	ARGOS Ready Mix LLC.	Columbus	Muscogee	B	37	700371	3600185	18.0	100.00	Yes	Yes	See Note 1
21500146	St. Francis Health, LLC d/b/a St. Francis Hospital	Columbus	Muscogee	SM	39	691627	3598338	26.8	7.00	Yes	Yes	See Note 1
21500148	Eastman Kodak Company	Columbus	Muscogee	SM	40	699490	3598454	19.6	100.00	Yes	Yes	See Note 1
21500150	The Medical Center Inc.	Columbus	Muscogee	B	42	689675	3595485	29.7	36.00	Yes	Yes	See Note 1
21500153	Stepan Company	Columbus	Muscogee	B	43	699006	3598684	19.9	41.30	Yes	Yes	See Note 1
21500154	International Paper Company	Columbus	Muscogee	SM	44	698973	3599307	19.6	10.00	Yes	Yes	See Note 1
21500158	Panasonic Battery Corp of America	Columbus	Muscogee	A	45	699203	3597557	20.3	3.00	Yes	No	Title V Source; Do not include in file review.
21500163	Matthews CW Contracting Co Inc. Plt 66	Fortson	Muscogee	SM	47	692449	3608164	24.1	16.00	Yes	Yes	See Note 1
21500164	Panasonic Battery Corporation of America - Lithium Division	Columbus	Muscogee	A	48	699203	3597557	20.3	100.00	Yes	No	Title V Source; Do not include in file review.
21500176	Denim North America, LLC	Columbus	Muscogee	B	49	698779	3598075	20.4	100.00	Yes	Yes	See Note 1
21500181	Pine Grove Landfill	Columbus	Muscogee	A	51	701788	3596459	18.8	100.00	Yes	No	Title V Source; Do not include in file review.
21500183	ICForm Inc	Columbus	Muscogee	SM	52	699678	3598388	19.5	3.34	Yes	Yes	See Note 1
21500190	South Columbus Water Resource Facility	Columbus	Muscogee	SM	56	690238	3587794	33.2	49.00	Yes	Yes	See Note 1
21500192	JPS Technology, INC.	Columbus	Muscogee	B	57	699708	3598666	19.3	3.70	Yes	Yes	See Note 1
21500208	Columbus Power Producers, LLC	Columbus	Muscogee	B	60	701788	3596459	18.8	1.22	Yes	Yes	See Note 1
26300012	Junction City Mining Company	Talbotton	Talbot	SM	62	733861	3614195	18.3	57.00	Yes	Yes	See Note 1
26900014	WI TAYLOR COUNTY DISPOSAL, LLC	Mauk	Taylor	A	63	745696	3593201	32.7	13.00	Yes	No	Title V Source; Do not include in file review.
26900017	MF & H Textiles Inc	Butler	Taylor	B	64	757309	3606490	40.7	100.00	Yes	Yes	See Note 1
28500093	Milliken & Company Pine Mountain Plant	Pine Mountain	Troup	B	65	696923	3642437	39.7	100.00	Yes	Yes	See Note 1
29300024	TenCate Protective Fabrics	Molena	Upson	A	66	734448	3650453	46.1	49.00	Yes	No	Title V Source; Do not include in file review.
29300025	SOUTHERN NATURAL GAS CO. - 1	Thomaston	Upson	A	67	757143	3631098	46.7	3.61	Yes	No	Title V Source; Do not include in file review.
29300029	Lancaster Energy Partners - Thomaston	Thomaston	Upson	A	68	751291	3643517	49.7	235.00	Yes	No	Title V Source; Do not include in file review.
29300036	Apollo Technologies, Animal Health and Sciences, Inc. - Thomaston Plant	Thomaston	Upson	B	69	752351	3641189	48.8	100.00	Yes	Yes	See Note 1

1. File review necessary.

Table D-22. NAAQS Inventory Sources

ID	Description	x-coord (m)	y-coord (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
GA1	SNG Ellerslie	704505.0	3610523.0	209.09	5.15	7.47	727.59	35.05	0.52
GA2	SNG Ellerslie	704506.0	3610516.0	209.09	5.15	7.47	727.59	35.05	0.52
GA3	SNG Ellerslie	704506.0	3610509.0	209.09	5.15	7.47	727.59	35.05	0.52
GA4	SNG Ellerslie	704506.0	3610497.0	209.09	5.15	7.47	727.59	35.05	0.52
GA5	SNG Ellerslie	704506.0	3610490.0	209.09	5.15	7.47	727.59	35.05	0.52
GA6	SNG Ellerslie	704506.0	3610475.0	209.09	4.23	11.77	672.04	25.91	0.76
GA7	SNG Ellerslie	704505.0	3610457.0	209.09	4.72	9.72	672.04	21.64	0.70
GA8	DMI Columbus	690660.0	3601037.2	129	0.35	10.00	293.00	15.00	0.50
GA9	United Technologies	704133.7	3602760.3	127	4.46	10.00	293.00	15.00	0.50
GA10	United States Army Fort Benning	691019.0	3581219.0	104.24	0.93	7.32	380.37	0.61	0.61
GA11	United States Army Fort Benning	691019.0	3581219.0	104.24	0.93	7.32	380.37	0.61	0.61
GA12	United States Army Fort Benning	691019.0	3581219.0	104.24	0.93	7.32	380.37	0.61	0.61
GA13	United States Army Fort Benning	695011.0	3583602.0	104.24	1.92	8.53	495.93	0.61	0.91
GA14	United States Army Fort Benning	695014.0	3583623.0	104.24	0.89	8.53	495.93	0.61	0.91
GA15	United States Army Fort Benning	695015.0	3583610.0	104.24	0.89	8.53	495.93	0.61	0.91
GA16	United States Army Fort Benning	691019.0	3581219.0	104.24	0.78	20.42	338.71	121.92	0.91
GA17	United States Army Fort Benning	691019.0	3581219.0	104.24	0.78	20.42	338.71	121.92	0.91
GA18	United States Army Fort Benning	691019.0	3581219.0	104.24	0.67	9.75	338.71	121.92	0.91
GA19	United States Army Fort Benning	691019.0	3581219.0	104.24	0.67	9.75	338.71	121.92	0.91
GA20	United States Army Fort Benning	691019.0	3581219.0	104.24	0.67	9.75	338.71	121.92	0.91
GA21	Taylor County Disposal LLC	745695.6	3593201.4	229	0.37	10.00	738.00	47.50	0.34
GA22	Taylor County LFGTE	745562.0	3593590.0	168.55	0.45	10.00	738.15	47.55	0.34
GA23	Taylor County LFGTE	745567.0	3593591.0	168.55	0.45	10.00	738.15	47.55	0.34
GA24	Taylor County LFGTE	745572.0	3593594.0	168.55	0.45	10.00	738.15	47.55	0.34
GA25	Taylor County LFGTE	745577.0	3593596.0	168.55	0.45	10.00	738.15	47.55	0.34
GA26	Taylor County LFGTE	745585.0	3593598.0	168.55	0.45	10.00	738.15	47.55	0.34
GA27	Taylor County LFGTE	745590.0	3593601.0	168.55	0.45	10.00	738.15	47.55	0.34
GA28	Taylor County LFGTE	745595.0	3593603.0	168.55	0.45	10.00	738.15	47.55	0.34
GA29	Taylor County LFGTE	745598.0	3593605.0	168.55	0.45	10.00	738.15	47.55	0.34
GA30	TenCate Protective Fabrics	734571.0	3650887.0	239.27	0.26	13.41	485.37	10.97	0.49
GA31	TenCate Protective Fabrics	734571.0	3650887.0	239.27	0.26	13.41	485.37	10.97	0.49
GA32	TenCate Protective Fabrics	734571.0	3650887.0	239.27	0.60	13.41	463.15	16.76	0.49
GA33	TenCate Protective Fabrics	734571.0	3650887.0	239.27	0.11	14.33	345.93	21.49	0.43
GA34	TenCate Protective Fabrics	734571.0	3650887.0	239.27	0.17	12.80	345.93	4.54	0.61
GA35	SNG Thomaston	757108.0	3631106.0	178.61	8.81	16.15	599.26	36.27	0.73
GA36	SNG Thomaston	757118.0	3631111.0	178.61	8.77	16.15	599.26	36.27	0.73
GA37	SNG Thomaston	757140.0	3631118.0	178.61	0.92	7.92	720.93	30.27	0.76
GA38	SNG Thomaston	757156.0	3631121.0	178.61	0.92	12.19	720.93	30.27	0.76
GA39	Columbus Power Producers EP1	701788.0	3596459.0	138.45	0.01	10.36	1088.71	18.29	0.05
GA40	Columbus Power Producers EP3	701788.0	3596459.0	138.45	0.02	10.36	1088.71	18.29	0.25
GA41	Eastman Kodak S001	699489.7	3598454.1	92.2	0.32	12.19	462.04	9.94	1.35
GA42	Eastman Kodak S002	699489.7	3598454.1	92.2	0.32	9.14	382.04	6.07	1.22
GA43	HPPE	699857.1	3599202.3	92.07	0.38	11.13	449.82	4.36	0.46
GA44	HPPE	699857.1	3599202.3	92.07	0.38	13.87	449.82	1.47	0.41
GA45	Koch Foods	703843.0	3631028.0	268.44	1.03	9.14	422.04	4.27	0.76
GA46	Stepan	698948.0	3598665.0	87.68	1.19	19.81	699.82	2.56	0.91
AL1	206-0030	684188.2	3602120.1	158.5	9.71	14.33	700.00	41.57	3.35
AL2	206-0030	684181.2	3602114.5	158.5	9.70	14.33	700.00	41.57	3.35
AL3	206-0030	684199.3	3602107.2	158.5	9.71	14.33	700.00	41.57	3.35
AL4	206-0030	684192.1	3602101.3	158.5	9.71	14.33	700.00	41.57	3.35
AL5	206-0036	678700.0	3609100.1	160.93	3.74	43.28	356.00	21.07	5.11
AL6	206-0036	678700.0	3609100.1	160.93	3.74	43.28	356.00	21.07	5.11
AL7	206-0036	678700.0	3609100.1	160.93	4.03	48.77	348.00	15.59	5.79
AL8	206-0036	678700.0	3609100.1	160.93	4.03	48.77	348.00	15.59	5.79
AL9	206-0036	678700.0	3609100.1	160.93	4.03	48.77	348.00	15.59	5.79
AL10	206-0036	678700.0	3609100.1	160.93	4.03	48.77	348.00	15.59	5.79
AL11	211-0013	690118.0	3589887.0	71.63	1.89	60.35	354.00	9.49	2.59
AL12	211-0013	690139.0	3589889.9	71.63	1.89	60.35	305.00	9.13	2.59
AL13	211-0019	688006.0	3587320.1	70.1	0.88	9.45	561.00	15.55	0.99
AL14	211-0020	687282.1	3586128.9	70.1	0.62	9.45	561.00	15.55	0.99
AL15	211-0020	687400.9	3586068.1	70.1	0.62	9.45	561.00	15.55	0.99
AL16	211-0020	687403.1	3586060.6	70.1	0.62	9.45	561.00	15.55	0.99

Table D-23. Facility-Wide TAP MER Analysis

Pollutant	CAS No.	Combustion Turbine Nos. 1 - 6 (T1 - T6) (tpy)	Fuel Heater Nos. 1 - 3 (H1 - H3) (tpy)	Fire Pump (tpy)	Fuel Oil Tank No. 1 (tpy)	Fuel Oil Tank No. 2 (tpy)	Fuel Oil Tank No. 3 (tpy)	Total Potential Emissions (tpy)	Total Potential Emissions (lb/yr)	MER (lb/yr)	Above MER? (Y/N)
1,3-Butadiene	106990	4.24E-01	--	3.16E-05	--	--	--	0.42	848.02	7.30	Y
Acetaldehyde	75070	5.68E-01	--	6.20E-04	--	--	--	0.57	1.14E+03	1.11E+03	Y
Acrolein	107028	5.12E-01	--	7.48E-05	--	--	--	0.51	1.02E+03	4.87	Y
Benzene	71432	3.75E-01	1.62E-04	7.54E-04	7.51E-04	8.97E-04	8.97E-04	0.38	756.76	31.63	Y
Ethylbenzene	100414	3.01E-01	--	--	1.22E-03	1.46E-03	1.46E-03	0.31	610.86	2.43E+05	N
Formaldehyde	50000	2.00E+00	5.80E-03	9.54E-04	--	--	--	2.01	4.01E+03	267.00	Y
Naphthalene	91203	6.31E-02	4.71E-05	6.86E-05	1.97E-04	2.35E-04	2.35E-04	6.39E-02	127.78	729.99	N
Propylene Oxide	75569	3.77E-01	--	--	--	--	--	0.38	754.73	656.99	Y
Toluene	108883	1.33E+00	2.63E-04	3.31E-04	8.98E-03	1.07E-02	1.07E-02	1.36	2.72E+03	1.22E+06	N
Xylene (Total)	1330207	1.28E+00	--	2.30E-04	2.38E-02	2.85E-02	2.85E-02	1.36	2.72E+03	2.43E+04	N
Arsenic	7440382	7.67E-03	1.55E-05	--	--	--	--	7.68E-03	15.36	5.67E-02	Y
Beryllium	7440417	6.09E-04	9.28E-07	--	--	--	--	6.10E-04	1.22	0.97	Y
Cadmium	7440439	5.61E-03	8.50E-05	--	--	--	--	5.69E-03	11.38	1.35	Y
Chromium	7440473	1.52E-02	1.08E-04	--	--	--	--	1.53E-02	30.68	58.40	N
Chromium (VI)	7440473(VI)	1.54E-04	4.33E-06	--	--	--	--	1.59E-04	0.32	2.02E-02	Y
Lead	7439921	2.60E-02	3.86E-05	--	--	--	--	2.60E-02	52.05	5.84	Y
Manganese	7439965	8.00E-01	2.94E-05	--	--	--	--	0.80	1.60E+03	12.17	Y
Mercury	7439976	1.13E-03	2.01E-05	--	--	--	--	1.15E-03	2.30	73.00	N
Nickel	7440020	3.29E-01	1.62E-04	--	--	--	--	0.33	657.36	38.64	Y
Selenium	7782492	2.34E-02	1.86E-06	--	--	--	--	2.34E-02	46.78	23.36	Y
Hexane	110543	--	1.39E-01	--	1.49E-04	1.78E-04	1.78E-04	0.14	279.27	1.70E+05	N
Cobalt	7440484	--	6.49E-06	--	--	--	--	6.49E-06	1.30E-02	11.68	N

Table D-24. TAP Modeling Emission Inputs (lb/hr)[1]

Pollutant	CAS No.	Combustion Turbine No. 1 (T1) lb/hr	Combustion Turbine No. 2 (T2) lb/hr	Combustion Turbine No. 3 (T3) lb/hr	Combustion Turbine No. 4 (T4) lb/hr	Combustion Turbine No. 5 (T5) lb/hr	Combustion Turbine No. 6 (T6) lb/hr	Fuel Heater No. 1 (H1) lb/hr	Fuel Heater No. 2 (H2) lb/hr	Fuel Heater No. 3 (H3) lb/hr	Fuel Oil Tank No. 1 lb/hr	Fuel Oil Tank No. 2 lb/hr	Fuel Oil Tank No. 3 lb/hr
1,3-Butadiene	106990	3.11E-01	3.11E-01	3.11E-01	3.11E-01	3.18E-01	3.18E-01	--	--	--	--	--	--
Acetaldehyde	75070	5.08E-02	5.08E-02	5.08E-02	5.08E-02	4.99E-02	4.99E-02	--	--	--	--	--	--
Acrolein	107028	3.22E-01	3.22E-01	3.22E-01	3.22E-01	3.29E-01	3.29E-01	--	--	--	--	--	--
Benzene	71432	1.65E-01	1.65E-01	1.65E-01	1.65E-01	1.69E-01	1.69E-01	1.24E-05	1.24E-05	1.24E-05	1.71E-04	2.05E-04	2.05E-04
Formaldehyde	50000	4.31E-01	4.31E-01	4.31E-01	4.31E-01	4.41E-01	4.41E-01	4.41E-04	4.41E-04	4.41E-04	--	--	--
Propylene Oxide	75569	3.37E-02	3.37E-02	3.37E-02	3.37E-02	3.31E-02	3.31E-02	--	--	--	--	--	--
Arsenic	7440382	5.64E-03	5.64E-03	5.64E-03	5.64E-03	5.76E-03	5.76E-03	1.18E-06	1.18E-06	1.18E-06	--	--	--
Beryllium	7440417	4.48E-04	4.48E-04	4.48E-04	4.48E-04	4.57E-04	4.57E-04	7.06E-08	7.06E-08	7.06E-08	--	--	--
Cadmium	7440439	4.12E-03	4.12E-03	4.12E-03	4.12E-03	4.21E-03	4.21E-03	6.47E-06	6.47E-06	6.47E-06	--	--	--
Chromium (VI)	7440473(VI)	1.13E-04	1.13E-04	1.13E-04	1.13E-04	1.16E-04	1.16E-04	3.29E-07	3.29E-07	3.29E-07	--	--	--
Lead	7439921	1.91E-02	1.91E-02	1.91E-02	1.91E-02	1.95E-02	1.95E-02	2.94E-06	2.94E-06	2.94E-06	--	--	--
Manganese	7439965	5.88E-01	5.88E-01	5.88E-01	5.88E-01	6.01E-01	6.01E-01	2.24E-06	2.24E-06	2.24E-06	--	--	--
Nickel	7440020	2.42E-01	2.42E-01	2.42E-01	2.42E-01	2.47E-01	2.47E-01	1.24E-05	1.24E-05	1.24E-05	--	--	--
Selenium	7782492	1.72E-02	1.72E-02	1.72E-02	1.72E-02	1.76E-02	1.76E-02	1.41E-07	1.41E-07	1.41E-07	--	--	--

1. For combustion turbines, emissions are based on max short-term emission rates from natural gas or fuel oil combustion.

Table D-25. TAP Modeling Emission Inputs (g/s)[1]

Pollutant	CAS No.	Combustion Turbine No. 1 (T1) g/s	Combustion Turbine No. 2 (T2) g/s	Combustion Turbine No. 3 (T3) g/s	Combustion Turbine No. 4 (T4) g/s	Combustion Turbine No. 5 (T5) g/s	Combustion Turbine No. 6 (T6) g/s	Fuel Heater No. 1 (H1) g/s	Fuel Heater No. 2 (H2) g/s	Fuel Heater No. 3 (H3) g/s	Fuel Oil Tank No. 1 g/s	Fuel Oil Tank No. 2 g/s	Fuel Oil Tank No. 3 g/s
1,3-Butadiene	106990	3.92E-02	3.92E-02	3.92E-02	3.92E-02	4.01E-02	4.01E-02	--	--	--	--	--	--
Acetaldehyde	75070	6.40E-03	6.40E-03	6.40E-03	6.40E-03	6.28E-03	6.28E-03	--	--	--	--	--	--
Acrolein	107028	4.06E-02	4.06E-02	4.06E-02	4.06E-02	4.15E-02	4.15E-02	--	--	--	--	--	--
Benzene	71432	2.08E-02	2.08E-02	2.08E-02	2.08E-02	2.13E-02	2.13E-02	1.56E-06	1.56E-06	1.56E-06	2.16E-05	2.58E-05	2.58E-05
Formaldehyde	50000	5.43E-02	5.43E-02	5.43E-02	5.43E-02	5.55E-02	5.55E-02	5.56E-05	5.56E-05	5.56E-05	--	--	--
Propylene Oxide	75569	4.25E-03	4.25E-03	4.25E-03	4.25E-03	4.17E-03	4.17E-03	--	--	--	--	--	--
Arsenic	7440382	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.26E-04	7.26E-04	1.48E-07	1.48E-07	1.48E-07	--	--	--
Beryllium	7440417	5.64E-05	5.64E-05	5.64E-05	5.64E-05	5.76E-05	5.76E-05	8.89E-09	8.89E-09	8.89E-09	--	--	--
Cadmium	7440439	5.19E-04	5.19E-04	5.19E-04	5.19E-04	5.31E-04	5.31E-04	8.15E-07	8.15E-07	8.15E-07	--	--	--
Chromium (VI)	7440473(VI)	1.43E-05	1.43E-05	1.43E-05	1.43E-05	1.46E-05	1.46E-05	4.15E-08	4.15E-08	4.15E-08	--	--	--
Lead	7439921	2.41E-03	2.41E-03	2.41E-03	2.41E-03	2.46E-03	2.46E-03	3.71E-07	3.71E-07	3.71E-07	--	--	--
Manganese	7439965	7.41E-02	7.41E-02	7.41E-02	7.41E-02	7.57E-02	7.57E-02	2.82E-07	2.82E-07	2.82E-07	--	--	--
Nickel	7440020	3.04E-02	3.04E-02	3.04E-02	3.04E-02	3.11E-02	3.11E-02	1.56E-06	1.56E-06	1.56E-06	--	--	--
Selenium	7782492	2.17E-03	2.17E-03	2.17E-03	2.17E-03	2.21E-03	2.21E-03	1.78E-08	1.78E-08	1.78E-08	--	--	--

1. For combustion turbines, emissions are based on max short-term emission rates from natural gas or fuel oil combustion.

Table D-26. TAP Modeling Results

Pollutant	CAS No.	Maximum 1-Hour Impact (µg/m3)	Maximum 15-Min Impact[1] (µg/m3)	15-min AAC[2] (µg/m3)	Is MGLC >15-min AAC? (Y/N)	Maximum 24-hr Impact (µg/m3)	24-hr AAC[2] (µg/m3)	Is MGLC > 24-hr AAC? (Y/N)	Maximum Annual Impact (µg/m3)	Annual AAC[2] (µg/m3)	Is MGLC > Annual AAC? (Y/N)
1,3-Butadiene	106990	1.71E-01	2.26E-01	1.10E+03	N	--	N/A	N/A	2.19E-03	3.00E-02	N
Acetaldehyde	75070	2.79E-02	3.69E-02	4.50E+03	N	--	N/A	N/A	3.50E-04	4.55E+00	N
Acrolein	107028	1.77E-01	2.34E-01	23	N	--	N/A	N/A	2.27E-03	2.00E-02	N
Benzene	71432	9.10E-02	1.20E-01	1.60E+03	N	--	N/A	N/A	2.44E-03	1.30E-01	N
Formaldehyde	50000	1.50E+00	1.98E+00	245	N	--	N/A	N/A	2.86E-02	1.10E+00	N
Propylene Oxide	75569	1.86E-02	2.45E-02	N/A	N/A	--	N/A	N/A	2.30E-04	2.70E+00	N
Arsenic	7440382	4.02E-03	5.31E-03	0	N	--	N/A	N/A	9.00E-05	2.33E-04	N
Beryllium	7440417	2.40E-04	3.17E-04	1	N	--	N/A	N/A	1.00E-05	4.00E-03	N
Cadmium	7440439	2.20E-02	2.90E-02	30	N	--	N/A	N/A	4.10E-04	5.56E-03	N
Chromium (VI)	7440473(VI)	1.12E-03	1.48E-03	10	N	--	N/A	N/A	2.00E-05	8.30E-05	N
Lead	7439921	1.06E-02	1.40E-02	N/A	N/A	2.55E-03	0.1	N	--	N/A	N/A
Manganese	7439965	2.89E-01	3.82E-01	500	N	--	N/A	N/A	3.94E-03	5.00E-02	N
Nickel	7440020	1.19E-01	1.57E-01	N/A	N/A	2.69E-02	0.8	N	--	N/A	N/A
Selenium	7782492	8.46E-03	1.12E-02	N/A	N/A	1.91E-03	0.5	N	--	N/A	N/A

1. 15-minute impacts equal the 1-hour impact times a factor of 1.32 per the Guideline, page 12.
2. Per Appendix A of Georgia EPD Toxics Guidance (Updated October 2018).

APPENDIX E. ELECTRONIC MODELING FILES

APPENDIX B – FEMA AND NWI MAPS

National Flood Hazard Layer FIRMette

FEMA

84°41'51"W 32°35'35"N

84°41'14"W 32°35'5"N

Feet 0 250 500 1,000 1,500 2,000

1:6,000

Basemap: USGS National Map: Orthoimagery: Data refreshed October, 2020

Legend

SEE FIS REPORT FOR DETAILED LEGEND AND INDEX MAP FOR FIRM PANEL LAYOUT

SPECIAL FLOOD HAZARD AREAS
- Without Base Flood Elevation (BFE) *Zone A, V, A99*
- With BFE or Depth *Zone AE, AO, AH, VE, AR*
- Regulatory Floodway

OTHER AREAS OF FLOOD HAZARD
- 0.2% Annual Chance Flood Hazard, Areas of 1% annual chance flood with average depth less than one foot or with drainage areas of less than one square mile *Zone X*
- Future Conditions 1% Annual Chance Flood Hazard *Zone X*
- Area with Reduced Flood Risk due to Levee. See Notes. *Zone X*
- Area with Flood Risk due to Levee *Zone D*

OTHER AREAS
- NO SCREEN Area of Minimal Flood Hazard *Zone X*
- Effective LOMRs
- Area of Undetermined Flood Hazard *Zone D*

GENERAL STRUCTURES
- Channel, Culvert, or Storm Sewer
- Levee, Dike, or Floodwall

OTHER FEATURES
- B 20.2 17.5 Cross Sections with 1% Annual Chance Water Surface Elevation
- 8 Coastal Transect
- 513 Base Flood Elevation Line (BFE)
- Limit of Study
- Jurisdiction Boundary
- Coastal Transect Baseline
- Profile Baseline
- Hydrographic Feature

MAP PANELS
- Digital Data Available
- No Digital Data Available
- Unmapped

N

The pin displayed on the map is an approximate point selected by the user and does not represent an authoritative property location.

This map complies with FEMA's standards for the use of digital flood maps if it is not void as described below. The basemap shown complies with FEMA's basemap accuracy standards

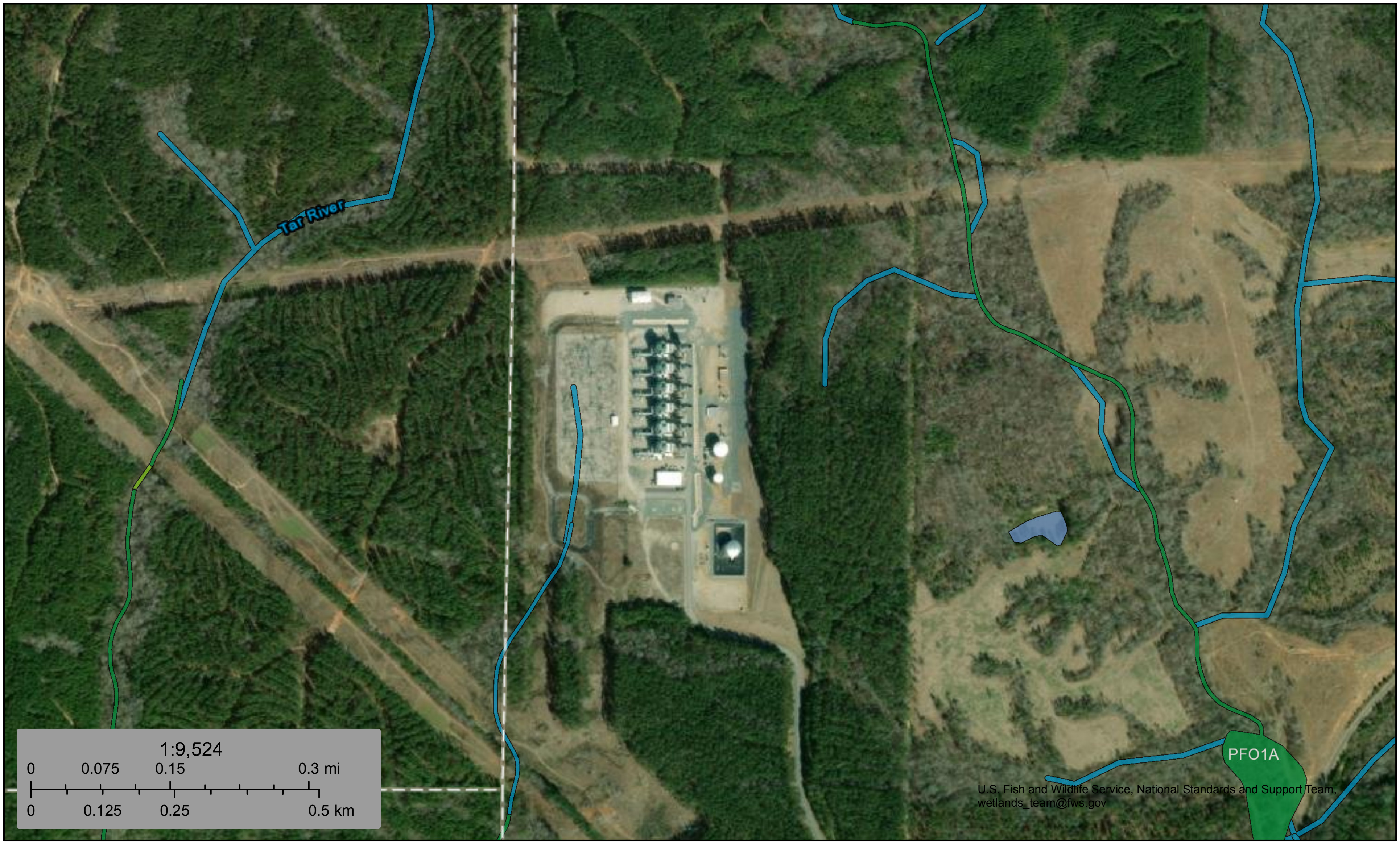
The flood hazard information is derived directly from the authoritative NFHL web services provided by FEMA. This map was exported on 3/7/2023 at 9:19 AM and does not reflect changes or amendments subsequent to this date and time. The NFHL and effective information may change or become superseded by new data over time.

This map image is void if the one or more of the following map elements do not appear: basemap imagery, flood zone labels, legend, scale bar, map creation date, community identifiers, FIRM panel number, and FIRM effective date. Map images for unmapped and unmodernized areas cannot be used for regulatory purposes.

U.S. Fish and Wildlife Service

National Wetlands Inventory

NWI_Talbot



March 7, 2023

Wetlands

- Estuarine and Marine Deepwater
- Estuarine and Marine Wetland
- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland
- Freshwater Pond
- Lake
- Other
- Riverine

This map is for general reference only. The US Fish and Wildlife Service is not responsible for the accuracy or currentness of the base data shown on this map. All wetlands related data should be used in accordance with the layer metadata found on the Wetlands Mapper web site.

APPENDIX C – USFWS IPAC REPORT AND STATE PROTECTED SPECIES

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Georgia Ecological Services Field Office
355 East Hancock Avenue
Room 320
Athens, GA 30601-2523
Phone: (706) 613-9493 Fax: (706) 613-6059

In Reply Refer To: July 31, 2023
Project Code: 2023-0110820
Project Name: Burns & McDonnell - Oglethorpe Power Company - Dual Fuel Conversion Project

Subject: List of threatened and endangered species that may occur in your proposed project location or may be affected by your proposed project

To Whom It May Concern:

Thank you for your request for information on federally listed species and important wildlife habitats that may occur in your project area. The U.S. Fish and Wildlife Service (Service) has responsibility for certain species of wildlife under the Endangered Species Act (ESA) of 1973 as amended (16 USC 1531 et seq.), the Migratory Bird Treaty Act (MBTA) as amended (16 USC 701-715), Fish and Wildlife Coordination Act (FWCA) (48 Stat. 401, as amended; 16 U.S.C. 661 et seq.) and the Bald and Golden Eagle Protection Act (BGEPA) as amended (16 USC 668-668c). We are providing the following guidance to assist you in determining which federally imperiled species may or may not occur within your project area and to recommend some conservation measures that can be included in your project design if you determine those species or designated critical habitat may be affected by your proposed project.

FEDERALLY-LISTED SPECIES AND DESIGNATED CRITICAL HABITAT

Attached is a list of endangered, threatened, and proposed species that may occur in your project area. Your project area may not necessarily include all or any of these species. Under the ESA, it is the responsibility of the Federal action agency, project proponent, or their designated representative to determine if a proposed action "may affect" endangered, threatened, or proposed species, or designated critical habitat, and if so, to consult with the Service further. Similarly, it is the responsibility of the Federal action agency or project proponent, not the Service, to make “no effect” determinations. If you determine that your proposed action will have “no effect” on threatened or endangered species or their respective critical habitat, you do not need to seek concurrence with the Service. Nevertheless, it is a violation of Federal law to harm or harass any federally listed threatened or endangered fish or wildlife species without the appropriate permit. If you need additional information to assist in your effect determination, please contact the Service.

If you determine that your proposed action may affect federally listed species, please consult with the Service. Through the consultation process, we will analyze information contained in a biological assessment or equivalent document that you provide. If your proposed action is associated with Federal funding or permitting, consultation will occur with the Federal agency under section 7(a)(2) of the ESA. Otherwise, an incidental take permit pursuant to section 10(a)(1)(B) of the ESA (also known as a Habitat Conservation Plan) may be necessary to exempt harm or harass federally listed threatened or endangered fish or wildlife species. For more information regarding formal consultation and HCPs, please see the Service's Section 7 Consultation Library and Habitat Conservation Plans Library Collections.

Action Area. The scope of federally listed species compliance not only includes direct effects, but also any indirect effects of project activities (e.g., equipment staging areas, offsite borrow material areas, or utility relocations). The action area is the spatial extent of an action's direct and indirect modifications or impacts to the land, water, or air (50 CFR 402.02). Large projects may have effects to land, water, or air outside the immediate footprint of the project, and these areas should be included as part of the action area. Effects to land, water, or air outside of a project footprint could include things like lighting, dust, smoke, and noise. To obtain a complete list of species, the action area should be uploaded or drawn in IPaC rather than just the project footprint.

New information based on updated surveys, changes in the abundance and distribution of species, changed habitat conditions, or other factors could change this list. Please feel free to contact us if you need more current information or assistance regarding the potential impacts to federally proposed, listed, and candidate species and federally designated and proposed critical habitat. Please note that under 50 CFR 402.12(e) of the regulations implementing section 7 of the Act, the accuracy of this species list should be verified after 90 days. This verification can be completed formally or informally as desired. An updated list may be requested through IPaC.

How to Submit a Project Review Package. If you determine that your action may affect any federally listed species and would like technical assistance from our office, please send us a complete project review package. A step by step guide is available at the Georgia Ecological Services Project Planning and Review page (https://www.fws.gov/office/georgia-ecological-services/project-planning-review).

Beginning April 1, 2023, requests for threatened and endangered species project reviews must be submitted to our office using the process described below. (If you are not emailing us to submit a project for review, your email will be forwarded to the appropriate staff.) This is a three-step process. All steps must be completed to ensure your project is reviewed by a biologist in our office and you receive a timely response. In brief the steps are:
Step 1. Request an official species list for your project through IPaC (Done!)
Step 2. Complete applicable Determination Keys
Step 3. Send your complete project project review package to **GAES_Assistance@FWS.gov** for review if no dKey is applicable or all aspects of the project are not addressed by dKeys, i.e. a species returned by IPaC does not have a dKey to address impacts to it. A complete project review package should include:

1. A description of the proposed action, including any measures intended to avoid, minimize, or offset effects of the action. The description shall provide sufficient detail to assess the effects of the action on listed species and critical habitat, such as the purpose of the action; duration and timing of the action; location (latitude and longitude); specific activities involving disturbance to land, water, and air, and how they will be carried out; current description of areas to be affected directly or indirectly by the action; and maps, drawings, or similar schematics of the action.
2. An updated Official Species List and dKey results
3. Biological Assessments (may include habitat assessments and information on the presence of listed species in the action area);
4. Description of effects of the action on species in the action area and, if relevant, effect determinations for species and critical habitat;
5. Conservation measures and any other available information related to the nature and scope of the proposed action relevant to its effects on listed species or designated critical habitat (e.g., management plans related to stormwater, vegetation, erosion and sediment plans). Visit the Georgia Conservation Planning Toolbox (https://www.fws.gov/story/conservation-tools-georgia) for information about conservation measures.
6. In the email subject line, use the following format to include the Project Code from your IPaC species list and the county in which the project is located (Example: Project Code: 2023-0049730 Gwinnett Co.). For Georgia Department of Transportation related projects, please work with the Office of Environmental Services ecologist to determine the appropriate USFWS transportation liaison.

The Georgia Ecological Services Field Office will send a response email within approximately 30 days of receipt with technical assistance or further recommendations for specific species.

WETLANDS AND FLOODPLAINS

Under Executive Orders 11988 and 11990, Federal agencies are required to minimize the destruction, loss, or degradation of wetlands and floodplains, and preserve and enhance their natural and beneficial values. These habitats should be conserved through avoidance, or mitigated to ensure that there would be no net loss of wetlands function and value. We encourage you to use the National Wetland Inventory (NWI) maps in conjunction with ground-truthing to identify wetlands occurring in your project area. The Service's NWI program website (https://www.fws.gov/program/national-wetlands-inventory) integrates digital map data with other resource information. We also recommend you contact the U.S. Army Corps of Engineers for permitting requirements under section 404 of the Clean Water Act if your proposed action could impact floodplains or wetlands.

MIGRATORY BIRDS

The MBTA prohibits the taking of migratory birds, nests, and eggs, except as permitted by the Service's Migratory Birds Program (https://fws.gov/program/migratory-birds). To minimize the likelihood of adverse impacts to migratory birds, we recommend construction activities occur outside the general bird nesting season from March through August, or that areas proposed for construction during the nesting season be surveyed, and when occupied, avoided until the young have fledged.

We recommend review of Birds of Conservation Concern to fully evaluate the effects to the birds at your site. This list identifies birds that are potentially threatened by disturbance and construction. It can be found at the Service's Migratory Birds Conservation Library Collection (https://fws.gov/library/collections/migratory-bird-conservation-documents).

Information related to best practices and migratory birds can be found at the Service's Avoiding and Minimizing Incidental Take of Migratory Birds Library Collection (https://fws.gov/library/collections/avoiding-and-minimizing-incidental-take-migratory-birds).

BALD AND GOLDEN EAGLES

The bald eagle (*Haliaeetus leucocephalus*) was delisted under the ESA on August 9, 2007. Both the bald eagle and golden eagle (*Aquila chrysaetos*) are still protected under the MBTA and BGEPA. The BGEPA affords both eagles protection in addition to that provided by the MBTA, in particular, by making it unlawful to "disturb" eagles. Under the BGEPA, the Service may issue limited permits to incidentally "take" eagles (e.g., injury, interfering with normal breeding, feeding, or sheltering behavior nest abandonment). For information on bald and golden eagle management guidelines, we recommend you review information provided at the Service's Bald and Golden Eagle Management Library Collection (https://fws.gov/library/collections/bald-and-golden-eagle-management).

NATIVE BATS

If your species list includes Indiana bat (*Myotis sodalis*) or northern long-eared bat (*M. septentrionalis*) and the project is expected to impact forested habitat that is appropriate for maternity colonies of these species, forest clearing should occur outside of the period when bats may be present. Federally listed bats could be actively present in forested landscapes from April

1 to October 15 of any year and have non-volant pups from May 15 to July 31 in any year. Non-volant pups are incapable of flight and are vulnerable to disturbance during that time.

Indiana, northern long-eared, and gray (*M. grisescens*) bats are all known to utilize bridges and culverts in Georgia. If your project includes maintenance, construction, or any other modification or demolition to transportation structures, a qualified individual should complete a survey of these structures for bats and submit your findings via the Georgia Bats in Bridges cell phone application, free on Apple and Android devices. Please include these findings in any biological assessment(s) or other documentation that is submitted to our office for technical assistance or consultation.

Additional information can be found at Georgia Ecological Services' Conservation Planning Toolbox and Bat Conservation in Georgia pages.

MONARCH BUTTERFLY

On December 20, 2020, the Service determined that listing the Monarch butterfly (*Danaus plexippus*) under the Endangered Species Act is warranted but precluded at this time by higher priority listing actions. With this finding, the monarch butterfly becomes a candidate for listing. The Service will review its status each year until we are able to begin developing a proposal to list the monarch.

As it is a candidate for listing, the Service welcomes conservation measures for this species. Recommended, and voluntary, conservation measures for projects in Georgia can be found at our Monarch Conservation in Georgia (https://www.fws.gov/project/monarch-conservation-georgia) page.

EASTERN INDIGO SNAKE

Our office has published guidance documents to assist project proponents in avoiding and minimizing potential impact to the eastern indigo snake. The Visual Encounter Survey Protocol for the Eastern Indigo Snake (*Drymarchon couperi*) in Georgia is recommended for project proponents or their designees to evaluate the possible presence of the Eastern indigo snake at a proposed project site. The Standard Protection Measures for the Eastern Indigo Snake (*Drymarchon couperi*) include educational materials and training that can help protect the species by making staff working on a project site aware of their presence and traits. In Georgia, indigo snakes are closely associated with the state-listed gopher tortoise (*Gopherus polyphemus*), a reptile that excavates extensive underground burrows that provide the snake shelter from winter cold and summer desiccation.

SOLAR ENERGY DEVELOPMENT

The Georgia Low Impact Solar Siting Tool (LISST) is available as a map layer in IPaC (Find it in the “Layers” Box > “Environmental Data”) and as a web application to provide project managers with the data to identify areas that may be preferred for low impact development. The tool seeks to support the acceleration of large-scale solar development in areas with less impact to the environment.

STATE AGENCY COORDINATION

Additional information that addresses at-risk or high priority natural resources can be found in the State Wildlife Action Plan (https://georgiawildlife.com/WildlifeActionPlan), at Georgia Department of Natural Resources, Wildlife Resources Division Biodiversity Portal (https://georgiawildlife.com/conservation/species-of-concern), Georgia's Natural, Archaeological, and Historic Resources GIS portal (https://www.gnahrgis.org/gnahrgis/index.do), and the Georgia Ecological Services HUC10 Watershed Guidance page.

Thank you for your concern for endangered and threatened species. We appreciate your efforts to identify and avoid impacts to listed and sensitive species in your project area. For further consultation on your proposed activity, please email gaes_assistance@fws.gov and reference the project county and your Service Project Tracking Number.

This letter constitutes Georgia Ecological Services' general comments under the authority of the Endangered Species Act.

Attachment(s):

- Official Species List
- Migratory Birds
- Wetlands

OFFICIAL SPECIES LIST

This list is provided pursuant to Section 7 of the Endangered Species Act, and fulfills the requirement for Federal agencies to "request of the Secretary of the Interior information whether any species which is listed or proposed to be listed may be present in the area of a proposed action".

This species list is provided by:

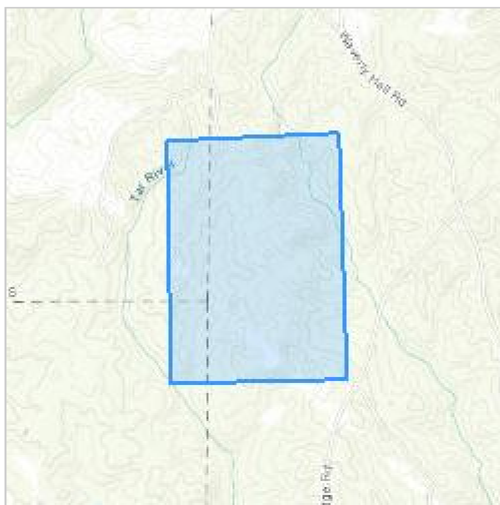
Georgia Ecological Services Field Office
355 East Hancock Avenue
Room 320
Athens, GA 30601-2523
(706) 613-9493

PROJECT SUMMARY

Project Code:	2023-0110820
Project Name:	Burns & McDonnell - Oglethorpe Power Company - Dual Fuel Conversion Project
Project Type:	Power Gen - Natural Gas
Project Description:	Oglethorpe Power Company's proposed Dual Fuel Conversion Project (Project) would occur at the existing Talbot Energy Facility (Facility), and includes converting four existing simple-cycle natural gas combustion turbines (CTs) into dual fuel capable CTs. All mechanical and software upgrades involved in the Project would occur within the existing Facility footprint, except for approximately 0.85 acres. It is not anticipated that the proposed Project would have any impact to natural resources.

Project Location:

The approximate location of the project can be viewed in Google Maps: https://www.google.com/maps/@32.586295899999996,-84.69101159138232,14z



Counties: Harris , Muscogee , and Talbot counties, Georgia

ENDANGERED SPECIES ACT SPECIES

There is a total of 6 threatened, endangered, or candidate species on this species list.

Species on this list should be considered in an effects analysis for your project and could include species that exist in another geographic area. For example, certain fish may appear on the species list because a project could affect downstream species.

IPaC does not display listed species or critical habitats under the sole jurisdiction of NOAA Fisheries[1], as USFWS does not have the authority to speak on behalf of NOAA and the Department of Commerce.

See the "Critical habitats" section below for those critical habitats that lie wholly or partially within your project area under this office's jurisdiction. Please contact the designated FWS office if you have questions.

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1. NOAA Fisheries, also known as the National Marine Fisheries Service (NMFS), is an office of the National Oceanic and Atmospheric Administration within the Department of Commerce.

BIRDS

NAME	STATUS
Whooping Crane *Grus americana* Population: U.S.A. (AL, AR, CO, FL, GA, ID, IL, IN, IA, KY, LA, MI, MN, MS, MO, NC, NM, OH, SC, TN, UT, VA, WI, WV, western half of WY) No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/758	Experimental Population, Non-Essential

REPTILES

NAME	STATUS
Alligator Snapping Turtle *Macrochelys temminckii* No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/4658	Proposed Threatened

INSECTS

NAME	STATUS
Monarch Butterfly *Danaus plexippus* No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/9743	Candidate

FLOWERING PLANTS

NAME	STATUS
Fringed Campion *Silene polypetala* No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/3738	Endangered
Michaux's Sumac *Rhus michauxii* No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/5217	Endangered
Relict Trillium *Trillium reliquum* No critical habitat has been designated for this species. Species profile: https://ecos.fws.gov/ecp/species/8489	Endangered

CRITICAL HABITATS

THERE ARE NO CRITICAL HABITATS WITHIN YOUR PROJECT AREA UNDER THIS OFFICE'S JURISDICTION.

YOU ARE STILL REQUIRED TO DETERMINE IF YOUR PROJECT(S) MAY HAVE EFFECTS ON ALL ABOVE LISTED SPECIES.

MIGRATORY BIRDS

Certain birds are protected under the Migratory Bird Treaty Act[1] and the Bald and Golden Eagle Protection Act[2].

Any person or organization who plans or conducts activities that may result in impacts to migratory birds, eagles, and their habitats should follow appropriate regulations and consider implementing appropriate conservation measures, as described below.

---

1. The Migratory Birds Treaty Act of 1918.
2. The Bald and Golden Eagle Protection Act of 1940.
3. 50 C.F.R. Sec. 10.12 and 16 U.S.C. Sec. 668(a)

The birds listed below are birds of particular concern either because they occur on the USFWS Birds of Conservation Concern (BCC) list or warrant special attention in your project location. To learn more about the levels of concern for birds on your list and how this list is generated, see the FAQ below. This is not a list of every bird you may find in this location, nor a guarantee that every bird on this list will be found in your project area. To see exact locations of where birders and the general public have sighted birds in and around your project area, visit the E-bird data mapping tool (Tip: enter your location, desired date range and a species on your list). For projects that occur off the Atlantic Coast, additional maps and models detailing the relative occurrence and abundance of bird species on your list are available. Links to additional information about Atlantic Coast birds, and other important information about your migratory bird list, including how to properly interpret and use your migratory bird report, can be found below.

For guidance on when to schedule activities or implement avoidance and minimization measures to reduce impacts to migratory birds on your list, click on the PROBABILITY OF PRESENCE SUMMARY at the top of your list to see when these birds are most likely to be present and breeding in your project area.

NAME	BREEDING SEASON
Chimney Swift *Chaetura pelagica* This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds Mar 15 to Aug 25
Eastern Whip-poor-will *Antrostomus vociferus* This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds May 1 to Aug 20
Kentucky Warbler *Oporornis formosus* This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds Apr 20 to Aug 20

NAME	BREEDING SEASON
Prairie Warbler *Dendroica discolor* This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds May 1 to Jul 31
Red-headed Woodpecker *Melanerpes erythrocephalus* This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds May 10 to Sep 10

PROBABILITY OF PRESENCE SUMMARY

The graphs below provide our best understanding of when birds of concern are most likely to be present in your project area. This information can be used to tailor and schedule your project activities to avoid or minimize impacts to birds. Please make sure you read and understand the FAQ "Proper Interpretation and Use of Your Migratory Bird Report" before using or attempting to interpret this report.

Probability of Presence (■)

Each green bar represents the bird's relative probability of presence in the 10km grid cell(s) your project overlaps during a particular week of the year. (A year is represented as 12 4-week months.) A taller bar indicates a higher probability of species presence. The survey effort (see below) can be used to establish a level of confidence in the presence score. One can have higher confidence in the presence score if the corresponding survey effort is also high.

How is the probability of presence score calculated? The calculation is done in three steps:

1. The probability of presence for each week is calculated as the number of survey events in the week where the species was detected divided by the total number of survey events for that week. For example, if in week 12 there were 20 survey events and the Spotted Towhee was found in 5 of them, the probability of presence of the Spotted Towhee in week 12 is 0.25.
2. To properly present the pattern of presence across the year, the relative probability of presence is calculated. This is the probability of presence divided by the maximum probability of presence across all weeks. For example, imagine the probability of presence in week 20 for the Spotted Towhee is 0.05, and that the probability of presence at week 12 (0.25) is the maximum of any week of the year. The relative probability of presence on week 12 is 0.25/0.25 = 1; at week 20 it is 0.05/0.25 = 0.2.
3. The relative probability of presence calculated in the previous step undergoes a statistical conversion so that all possible values fall between 0 and 10, inclusive. This is the probability of presence score.

Breeding Season (■)

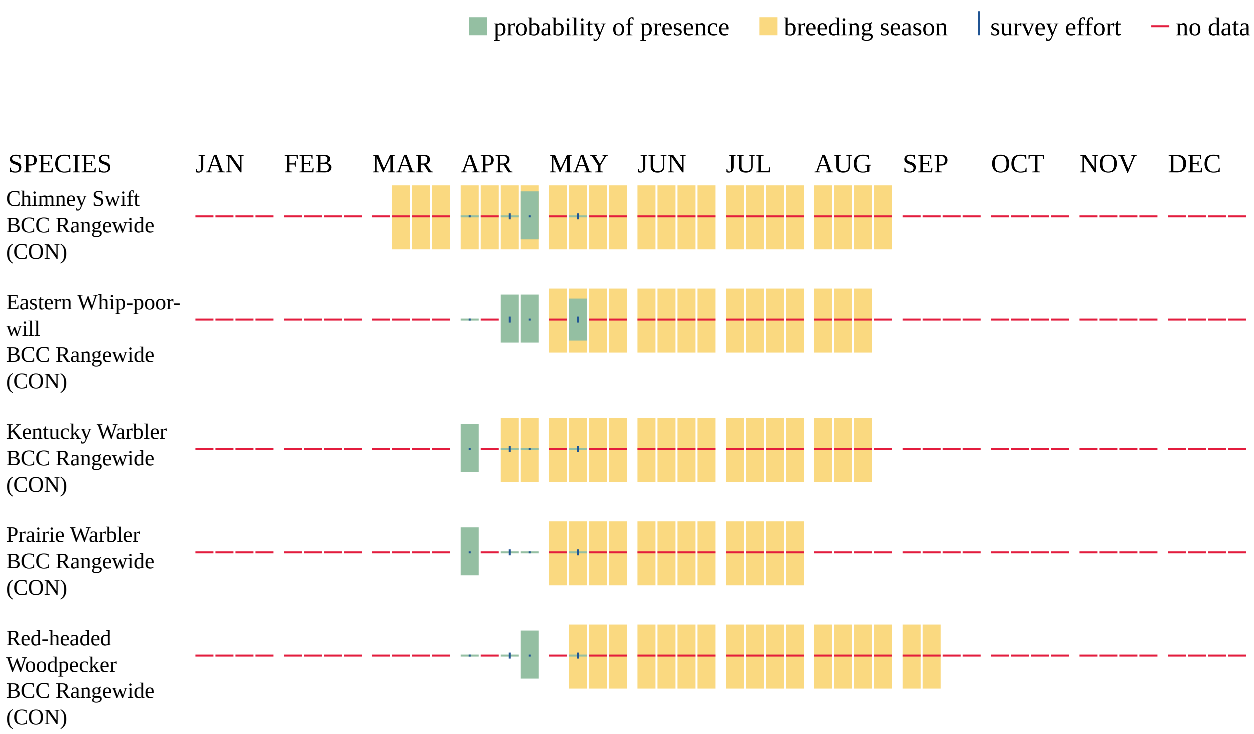
Yellow bars denote a very liberal estimate of the time-frame inside which the bird breeds across its entire range. If there are no yellow bars shown for a bird, it does not breed in your project area.

Survey Effort (|)

Vertical black lines superimposed on probability of presence bars indicate the number of surveys performed for that species in the 10km grid cell(s) your project area overlaps. The number of surveys is expressed as a range, for example, 33 to 64 surveys.

No Data (–)
A week is marked as having no data if there were no survey events for that week.

Survey Timeframe
Surveys from only the last 10 years are used in order to ensure delivery of currently relevant information. The exception to this is areas off the Atlantic coast, where bird returns are based on all years of available data, since data in these areas is currently much more sparse.



Additional information can be found using the following links:

- Birds of Conservation Concern https://www.fws.gov/program/migratory-birds/species
- Measures for avoiding and minimizing impacts to birds https://www.fws.gov/library/collections/avoiding-and-minimizing-incidental-take-migratory-birds
- Nationwide conservation measures for birds https://www.fws.gov/sites/default/files/documents/nationwide-standard-conservation-measures.pdf

MIGRATORY BIRDS FAQ

Tell me more about conservation measures I can implement to avoid or minimize impacts to migratory birds.

Nationwide Conservation Measures describes measures that can help avoid and minimize impacts to all birds at any location year round. Implementation of these measures is particularly important when birds are most likely to occur in the project area. When birds may be breeding in the area, identifying the locations of any active nests and avoiding their destruction is a very helpful impact minimization measure. To see when birds are most likely to occur and be breeding in your project area, view the Probability of Presence Summary. Additional measures or permits may be advisable depending on the type of activity you are conducting and the type of infrastructure or bird species present on your project site.

What does IPaC use to generate the list of migratory birds that potentially occur in my specified location?
The Migratory Bird Resource List is comprised of USFWS Birds of Conservation Concern (BCC) and other species that may warrant special attention in your project location.

The migratory bird list generated for your project is derived from data provided by the Avian Knowledge Network (AKN). The AKN data is based on a growing collection of survey, banding, and citizen science datasets and is queried and filtered to return a list of those birds reported as occurring in the 10km grid cell(s) which your project intersects, and that have been identified as warranting special attention because they are a BCC species in that area, an eagle (Eagle Act requirements may apply), or a species that has a particular vulnerability to offshore activities or development.

Again, the Migratory Bird Resource list includes only a subset of birds that may occur in your project area. It is not representative of all birds that may occur in your project area. To get a list of all birds potentially present in your project area, please visit the Rapid Avian Information Locator (RAIL) Tool.

What does IPaC use to generate the probability of presence graphs for the migratory birds potentially occurring in my specified location?
The probability of presence graphs associated with your migratory bird list are based on data provided by the Avian Knowledge Network (AKN). This data is derived from a growing collection of survey, banding, and citizen science datasets.

Probability of presence data is continuously being updated as new and better information becomes available. To learn more about how the probability of presence graphs are produced and how to interpret them, go the Probability of Presence Summary and then click on the "Tell me about these graphs" link.

How do I know if a bird is breeding, wintering or migrating in my area?
To see what part of a particular bird's range your project area falls within (i.e. breeding, wintering, migrating or year-round), you may query your location using the RAIL Tool and look at the range maps provided for birds in your area at the bottom of the profiles provided for each bird in your results. If a bird on your migratory bird species list has a breeding season associated with it, if that bird does occur in your project area, there may be nests present at some point within the timeframe specified. If "Breeds elsewhere" is indicated, then the bird likely does not breed in your project area.

What are the levels of concern for migratory birds?

Migratory birds delivered through IPaC fall into the following distinct categories of concern:

1. "BCC Rangewide" birds are Birds of Conservation Concern (BCC) that are of concern throughout their range anywhere within the USA (including Hawaii, the Pacific Islands, Puerto Rico, and the Virgin Islands);
2. "BCC - BCR" birds are BCCs that are of concern only in particular Bird Conservation Regions (BCRs) in the continental USA; and
3. "Non-BCC - Vulnerable" birds are not BCC species in your project area, but appear on your list either because of the Eagle Act requirements (for eagles) or (for non-eagles) potential susceptibilities in offshore areas from certain types of development or activities (e.g. offshore energy development or longline fishing).

Although it is important to try to avoid and minimize impacts to all birds, efforts should be made, in particular, to avoid and minimize impacts to the birds on this list, especially eagles and BCC species of rangewide concern. For more information on conservation measures you can implement to help avoid and minimize migratory bird impacts and requirements for eagles, please see the FAQs for these topics.

Details about birds that are potentially affected by offshore projects
For additional details about the relative occurrence and abundance of both individual bird species and groups of bird species within your project area off the Atlantic Coast, please visit the Northeast Ocean Data Portal. The Portal also offers data and information about other taxa besides birds that may be helpful to you in your project review. Alternately, you may download the bird model results files underlying the portal maps through the NOAA NCCOS Integrative Statistical Modeling and Predictive Mapping of Marine Bird Distributions and Abundance on the Atlantic Outer Continental Shelf project webpage.

Bird tracking data can also provide additional details about occurrence and habitat use throughout the year, including migration. Models relying on survey data may not include this information. For additional information on marine bird tracking data, see the Diving Bird Study and the nanotag studies or contact Caleb Spiegel or Pam Loring.

What if I have eagles on my list?
If your project has the potential to disturb or kill eagles, you may need to obtain a permit to avoid violating the Eagle Act should such impacts occur.

Proper Interpretation and Use of Your Migratory Bird Report
The migratory bird list generated is not a list of all birds in your project area, only a subset of birds of priority concern. To learn more about how your list is generated, and see options for identifying what other birds may be in your project area, please see the FAQ "What does IPaC use to generate the migratory birds potentially occurring in my specified location". Please be aware this report provides the "probability of presence" of birds within the 10 km grid cell(s) that overlap your project; not your exact project footprint. On the graphs provided, please also look carefully at the survey effort (indicated by the black vertical bar) and for the existence of the "no data" indicator (a red horizontal bar). A high survey effort is the key component. If the survey effort is high, then the probability of presence score can be viewed as more dependable. In contrast, a low survey effort bar or no data bar means a lack of data and, therefore, a lack of

certainty about presence of the species. This list is not perfect; it is simply a starting point for identifying what birds of concern have the potential to be in your project area, when they might be there, and if they might be breeding (which means nests might be present). The list helps you know what to look for to confirm presence, and helps guide you in knowing when to implement conservation measures to avoid or minimize potential impacts from your project activities, should presence be confirmed. To learn more about conservation measures, visit the FAQ "Tell me about conservation measures I can implement to avoid or minimize impacts to migratory birds" at the bottom of your migratory bird trust resources page.

WETLANDS

Impacts to NWI wetlands and other aquatic habitats may be subject to regulation under Section 404 of the Clean Water Act, or other State/Federal statutes.

For more information please contact the Regulatory Program of the local U.S. Army Corps of Engineers District.

Please note that the NWI data being shown may be out of date. We are currently working to update our NWI data set. We recommend you verify these results with a site visit to determine the actual extent of wetlands on site.

FRESHWATER POND

- PUBHh

RIVERINE

- R5UBH
- R4SBC

FRESHWATER FORESTED/SHRUB WETLAND

- PFO1A

IPAC USER CONTACT INFORMATION

Agency:	Burns & McDonnell
Name:	Madeline Long
Address:	4004 Summit Blvd NE
Address Line 2:	Suite 1200
City:	Atlanta
State:	GA
Zip:	30319
Email	mrlong@burnsmcd.com
Phone:	6788953532

Scientific Name	Common Name	GA Prot	US Prot	GRank	Rnd GRank	SRank	Rnd SRank	SwapStatus	ES_ID	Element Code	Group	Georgia Habitat Summary	EO Count	Export Date
Dryobates borealis	Red-cockaded Woodpecker	E	LE	G3	G3	S2	S2	Yes	18726	ABNYF07060	Animal	Open pine woods; pine savannas	76	February 3, 2023
Silene polypetala	Fringed Campion	E	LE	G2	G2	S2	S2	Yes	18409	PDCAR0U1E0	Plant	Mesic deciduous forests	38	February 3, 2023
Trillium reliquum	Relict Trillium	E	LE	G3	G3	S3	S3	Yes	17442	PMLIL200S0	Plant	Mesic hardwood forests; limesink forests; usually with Fagus and Tilia	52	February 3, 2023
Chamaecyparis thyoides	Atlantic White-cedar	R	null	G4	G4	S2	S2	Yes	20334	PGCUP03030	Plant	Clearwater stream swamps in fall line sandhills	44	February 3, 2023
Etheostoma parvipinne	Goldstripe Darter	R	null	G4G5	G4	S2S3	S2	Yes	17335	AFCQC02570	Animal	Small sluggish streams and spring seepage areas in vegetated habitat	26	February 3, 2023
Lithobates capito	Gopher Frog	R	null	G2G3	G2	S2S3	S2	Yes	21226	AAABH01270	Animal	Sandhills; dry pine flatwoods; breed in isolated wetlands	64	February 3, 2023
Macbridea caroliniana	Carolina Bogmint	R	null	G2G3	G2	S1	S1	Yes	16791	PDLAM0Y020	Plant	Bogs; marshes; alluvial woods	12	February 3, 2023
Myriophyllum laxum	Lax Water-milfoil	R	null	G3	G3	S2S3	S2	No	15307	PDHAL04090	Plant	Bluehole spring runs; shallow, sandy, swift-flowing creeks; clear, cool ponds	27	February 3, 2023
Nestronia umbellula	Indian Olive	R	null	G4	G4	S3	S3	Yes	18249	PDSAN05010	Plant	Mixed with dwarf shrubby heaths in oak-hickory-pine woods; often in transition areas between	55	February 3, 2023
Pityopsis pinifolia	Sandhill Golden-aster	R	null	G4	G4	S2	S2	No	17759	PDAST7B070	Plant	Sandhills near fall line	19	February 3, 2023
Procambarus versutus	Sly Crayfish	R	null	G5	G5	S1	S1	Yes	16614	ICMAL14A40	Animal	Found in debris in moderately swift streams. Found in root masses and plants.	17	February 3, 2023
Pteronotropis euryzonus	Broadstripe Shiner	R	null	G3	G3	S3	S3	Yes	16092	AFCJB59010	Animal	Flowing areas of medium sized streams associated with sandy substrate and woody debris or	39	February 3, 2023
Croomia pauciflora	Croomia	T	null	G3	G3	S2	S2	Yes	18172	PMSTE01010	Plant	Mesic hardwood forests, usually with Fagus and Tilia	19	February 3, 2023
Geomys pinetis	Southeastern Pocket Gopher	T	null	G5	G5	S3	S3	Yes	18839	AMAFC02040	Animal	Sandy well-drained soils in open pine woodlands with grassy or herbaceous groundcover; fields and	52	February 3, 2023
Gopherus polyphemus	Gopher Tortoise	T	Null	G3	G3	S3	S3	Yes	20476	ARAAF01030	Animal	Sandhills; dry hammocks; longleaf pine-turkey oak woods; old fields	329	February 3, 2023
Heterodon simus	Southern Hognose Snake	T	null	G2	G2	S1S2	S1	Yes	20606	ARADB17030	Animal	Sandhills; fallow fields; longleaf pine-turkey oak	67	February 3, 2023
Pinguicula primuliflora	Clearwater Butterwort	T	null	G3G4	G3	S1	S1	Yes	15432	PDLNT01060	Plant	In shallow, sandy, clearwater streams and seeps; Atlantic whitecedar swamps	12	February 3, 2023
Sarracenia rubra ssp. gulfensis	Gulf Sweet Pitcherplant	T	null	G3G4TNR	TNR	S2	S2	Yes	18435	PDSAR02087	Plant	Fall Line sandhill bogs; whitecedar swamps	49	February 3, 2023
Stylisma pickeringii var. pickeringii	Pickering's Morning-glory	T	null	G4T3	T3	S2	S2	No	21939	PDCON0H052	Plant	Open, dry, oak scrub of sandhills	45	February 3, 2023

APPENDIX D – AGENCY COORDINATION LETTERS

BURNS McDONNELL

July 10, 2023
Mr. Kenneth Chapman
Vice Chairman, District 2 Commissioner
Talbot County Board of Commissioners
35 West Madison Street
PO Box 155
Talbotton, GA 31827

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Chapman:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

The Project would improve the efficiency and reliability for the 38 members of Oglethorpe, a not-for-profit generation cooperative. These upgrades would result in an increase in annual air emissions, requiring a modification to the Facility's air quality permit. A small increase in water usage and discharge is also expected. Implementation of the Project is not expected to increase the noise from the Talbot County Facility above historical levels nor will it require changes in the gas supply infrastructure for the Talbot County Facility. All infrastructure improvement and ground disturbing activities would occur within the existing Facility footprint, with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded.

This letter requests that your agency participate in this Project by providing information on the resources, issues, and impacts that will be addressed in the ER documentation. A Project Site Map and a Project Layout Map included in Appendix A for your reference. Your input on any of the following resources is appreciated:

- Land use
- Aesthetics
- Water quality and wetlands
- Soils and geology
- Wildlife, vegetation and fisheries, including threatened and endangered species
- Socioeconomics (population, employment, growth, development)
- Hazardous materials sites
- Cultural resources (historic and archaeological sites, cemeteries)
- Transportation and roads (airport and roadway expansions, construction, operations and maintenance)

Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

★ Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Cen

July 10, 2023
Ms. Denesia Cheek
Southeast Regional Air Resource Coordinator
National Park Service, Air Resource Division
NPS-Air PO Box 25287
Denver, CO, 80225

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Ms. Cheek:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

The Project would improve the efficiency and reliability for the 38 members of Oglethorpe, a not-for-profit generation cooperative. These upgrades would result in an increase in annual air emissions, requiring a modification to the Facility's air quality permit. A small increase in water usage and discharge is also expected. Implementation of the Project is not expected to increase the noise from the Talbot County Facility above historical levels nor will it require changes in the gas supply infrastructure for the Talbot County Facility. All infrastructure improvement and ground disturbing activities would occur within the existing Facility footprint, with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded.

This letter requests that your agency participate in this Project by providing information on the resources, issues, and impacts that will be addressed in the ER documentation. A Project Site Map and a Project Layout Map included in Appendix A for your reference. Your input on any of the following resources is appreciated:

- Land use
- Aesthetics
- Water quality and wetlands
- Soils and geology
- Wildlife, vegetation and fisheries, including threatened and endangered species
- Socioeconomics (population, employment, growth, development)
- Hazardous materials sites
- Cultural resources (historic and archaeological sites, cemeteries)
- Transportation and roads (airport and roadway expansions, construction, operations and maintenance)

Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

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US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

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Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Ce

BURNS McDONNELL

July 10, 2023
Mr. Nigel Anthony Couch
District 3 Commissioner
Talbot County Board of Commissioners
35 West Madison Street
PO Box 155
Talbotton, GA 31827

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Couch:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

The Project would improve the efficiency and reliability for the 38 members of Oglethorpe, a not-for-profit generation cooperative. These upgrades would result in an increase in annual air emissions, requiring a modification to the Facility's air quality permit. A small increase in water usage and discharge is also expected. Implementation of the Project is not expected to increase the noise from the Talbot County Facility above historical levels nor will it require changes in the gas supply infrastructure for the Talbot County Facility. All infrastructure improvement and ground disturbing activities would occur within the existing Facility footprint, with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded.

4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

This letter requests that your agency participate in this Project by providing information on the resources, issues, and impacts that will be addressed in the ER documentation. A Project Site Map and a Project Layout Map included in Appendix A for your reference. Your input on any of the following resources is appreciated:

- Land use
- Aesthetics
- Water quality and wetlands
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- Wildlife, vegetation and fisheries, including threatened and endangered species
- Socioeconomics (population, employment, growth, development)
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Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
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APPENDIX A

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

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US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

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Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

BURNS McDONNELL

July 10, 2023
Mr. Jeff Cown
Division Director
Georgia Department of Natural Resources, Historic Preservation Division
2610 GA Hwy 155 SW
Stockbridge, GA, 30281

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Cown:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

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- Land use
- Aesthetics
- Water quality and wetlands
- Soils and geology
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Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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July 10, 2023
Mr. Stephen Damaske
Stationary Source Permitting Manager
GA DNR, GA Environmental Protection Division, Air Protection Branch
4244 International Parkway
Suite 120
Atlanta, GA 30354

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Damaske:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
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APPENDIX A

★ Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map

Oglethorpe Power

Talbot Energy Facility,

Dual Fuel Conversion Project

Oglethorpe Power Corporation

Talbot County, GA

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BURNS McDONNELL

July 10, 2023
Mr. Eric Duff
Administrator
GA Department of Transportation, Environmental Services
600 West Peachtree Street NW
16th Floor
Atlanta, GA 30308

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Duff:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
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APPENDIX A

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
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July 10, 2023
Mr. Kendric Holder
District Conservationist
Natural Resources Conservation Service
111 Baker St
Suite D
Buena Vista, GA 31803

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Holder:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

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Project Boundary
Additional Clearing
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NORTH
400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
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BURNS McDONNELL

July 10, 2023
Mr. Franklin Holmes
Vice Chairman, District 4 Commissioner
Talbot County Board of Commissioners
253 Chestnut Grove Rd
Shiloh, GA 31826

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Holmes:

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Mr. Franklin Holmes
Talbot County Board of Commissioners
July 10, 2023
Page 2

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Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

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APPENDIX A

4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

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NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
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Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

July 10, 2023
Ms. Ntale Kajumba
Chief, NEPA Program Office
U.S. Environmental Protection Agency, Atlanta Federal Center
61 Forsyth Street SW
Mail code: 9T25
Atlanta, GA 30303

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Ms. Kajumba:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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US Feet

BURNS McDONNELL

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Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

July 10, 2023
Mr. Tony Lamar
Mayor
City of Talbotton
15 S Washington Ave
PO Box 215
Talbotton, GA 31827

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Lamar:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Burns & McDonnell, Project Manager

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July 10, 2023
Mr. Tyler Peek, P.E.
District Engineer
GA Department of Transportation
151 Transportation Blvd
Thomaston, GA 30286

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Peek:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

The Project would improve the efficiency and reliability for the 38 members of Oglethorpe, a not-for-profit generation cooperative. These upgrades would result in an increase in annual air emissions, requiring a modification to the Facility's air quality permit. A small increase in water usage and discharge is also expected. Implementation of the Project is not expected to increase the noise from the Talbot County Facility above historical levels nor will it require changes in the gas supply infrastructure for the Talbot County Facility. All infrastructure improvement and ground disturbing activities would occur within the existing Facility footprint, with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded.

This letter requests that your agency participate in this Project by providing information on the resources, issues, and impacts that will be addressed in the ER documentation. A Project Site Map and a Project Layout Map included in Appendix A for your reference. Your input on any of the following resources is appreciated:

- Land use
- Aesthetics
- Water quality and wetlands
- Soils and geology
- Wildlife, vegetation and fisheries, including threatened and endangered species
- Socioeconomics (population, employment, growth, development)
- Hazardous materials sites
- Cultural resources (historic and archaeological sites, cemeteries)
- Transportation and roads (airport and roadway expansions, construction, operations and maintenance)

Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
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July 10, 2023
Mr. Terrance Rudolph
State Conservationist
Natural Resources Conservation Service, Georgia State Office
355 East Hancock Ave
Athens, GA 30601

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Rudolph:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
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APPENDIX A

Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

Project Location Map

Oglethorpe Power

Talbot Energy Facility,

Dual Fuel Conversion Project

Oglethorpe Power Corporation

Talbot County, GA

BURNS McDONNELL

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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July 10, 2023
Mr. William Rutlin
Chief, Coastal Branch
U.S. Army Corps of Engineers, Savannah District – Regulatory Division
100 W. Oglethorpe Ave
Savannah, GA 31402

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Rutlin:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

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Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
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APPENDIX A

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Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

BURNS McDONNELL

July 10, 2023
Mr. Larry Sparks
Chairman, District 5 Commissioner
Talbot County Board of Commissioners
35 West Madison Street
PO Box 155
Talbotton, GA 31827

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Sparks:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

★ Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map

Oglethorpe Power

Talbot Energy Facility,

Dual Fuel Conversion Project

Oglethorpe Power Corporation

Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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BURNS McDONNELL

July 10, 2023
Ms. Joyce Stanley
Regional Environmental Officer – Atlanta
U.S. Department of the Interior, Office of Environmental Policy and Compliance
75 Ted Turner Drive SW
Suite 1144
Atlanta, GA 30303

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Ms. Stanley:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

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Thank you for your participation and support of this Project.

Sincerely,

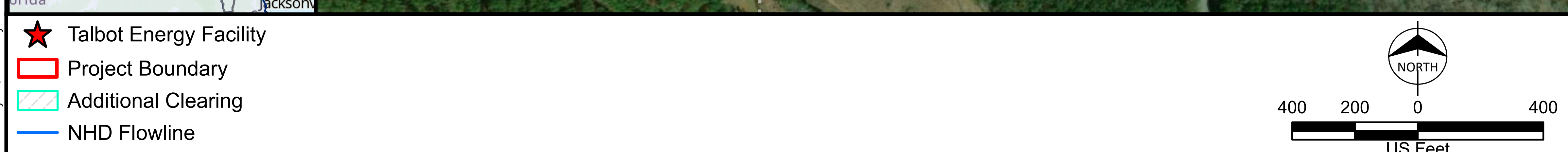
Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com



BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

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Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

July 10, 2023
Ms. Anna Truszczynski
Branch Chief
GA DNR, GA Environmental Protection Division, Watershed Protection Branch
2 Martin Luther King Jr. Drive
Suite 14701
Atlanta, GA 30334

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Ms. Truszczynski:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

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Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

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Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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July 10, 2023
Mr. Bill Wikoff
Supervisory Biologist
U.S. Fish and Wildlife Services, Georgia Ecological Services
4890 Wildlife Drive NE
Townsend, GA 31331

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Wikoff:

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Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

- ★ Talbot Energy Facility
- Project Boundary
- Additional Clearing
- NHD Flowline

NORTH

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US Feet

BURNS McDONNELL

Project Location Map
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Oglethorpe Power Corporation
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July 10, 2023
Mr. Walter Wilson Jr.
District 1 Commissioner
Talbot County Board of Commissioners
35 West Madison Street
PO Box 155
Talbotton, GA 31827

Re: Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project

Dear Mr. Wilson:

Oglethorpe Power Corporation ("Oglethorpe") will be conducting an Environmental Assessment (EA) for the U.S. Department of Agriculture's (USDA) Rural Utilities Services (RUS), as required by the National Environmental Policy Act (NEPA). Oglethorpe plans to submit a financing request to the USDA's RUS to upgrade their existing, natural gas-fired combustion turbines at Talbot Energy Facility to have dual fuel firing capabilities for natural gas and diesel fuel oil. Burns & McDonnell has been contracted by Oglethorpe to prepare an environmental report (ER) for submittal to RUS for preparation of an EA for the Dual Fuel Conversion Project (the "Project") at Oglethorpe's Talbot Energy Facility located in Talbot County, near Box Springs, Georgia (the "Facility") at 9125 Cartledge Road (32.588843°N, -84.692115°W).

Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in the Facility's existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, a new aboveground demineralized water storage tank, and associated new piping and infrastructure. A project location map and proposed site plan are enclosed for reference. These additions would increase reliability in the event natural gas is curtailed or cut-off to the Facility in times of heavy loads, and would serve as a backup fuel source to maintain plant operations. No new combustion turbines will be constructed as part of the Project.

The Project would improve the efficiency and reliability for the 38 members of Oglethorpe, a not-for-profit generation cooperative. These upgrades would result in an increase in annual air emissions, requiring a modification to the Facility's air quality permit. A small increase in water usage and discharge is also expected. Implementation of the Project is not expected to increase the noise from the Talbot County Facility above historical levels nor will it require changes in the gas supply infrastructure for the Talbot County Facility. All infrastructure improvement and ground disturbing activities would occur within the existing Facility footprint, with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded.

4004 Summit Boulevard NE \ Suite 1200 \ Atlanta, GA 30319
O 770-587-4776 \ F 770-587-4772 \ burnsmcd.com

This letter requests that your agency participate in this Project by providing information on the resources, issues, and impacts that will be addressed in the ER documentation. A Project Site Map and a Project Layout Map included in Appendix A for your reference. Your input on any of the following resources is appreciated:

- Land use
- Aesthetics
- Water quality and wetlands
- Soils and geology
- Wildlife, vegetation and fisheries, including threatened and endangered species
- Socioeconomics (population, employment, growth, development)
- Hazardous materials sites
- Cultural resources (historic and archaeological sites, cemeteries)
- Transportation and roads (airport and roadway expansions, construction, operations and maintenance)

Please contact me at (470) 508-9904 or at sskent@burnsmcd.com with your feedback on these items and if you need additional information. We would appreciate your response within thirty (30) days of your receipt of this request.

Thank you for your participation and support of this Project.

Sincerely,

Sara Kent

Sara Kent
Burns & McDonnell, Project Manager

Enclosure Attachment
cc: Type name(s) for copies of letter

APPENDIX A

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

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Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Bryant J. Celestine
Tribal Historic Preservation Officer
Alabama-Coushatta Tribe of Texas
571 State Park Road 56
Livingston, TX 77351

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Celestine:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.

In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Alabama-Coushatta Tribe of Texas in Talbot County, Georgia. Should the Alabama-Coushatta

Tribe of Texas elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment

CC Celestine.bryant@actribe.org

★ Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map

Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

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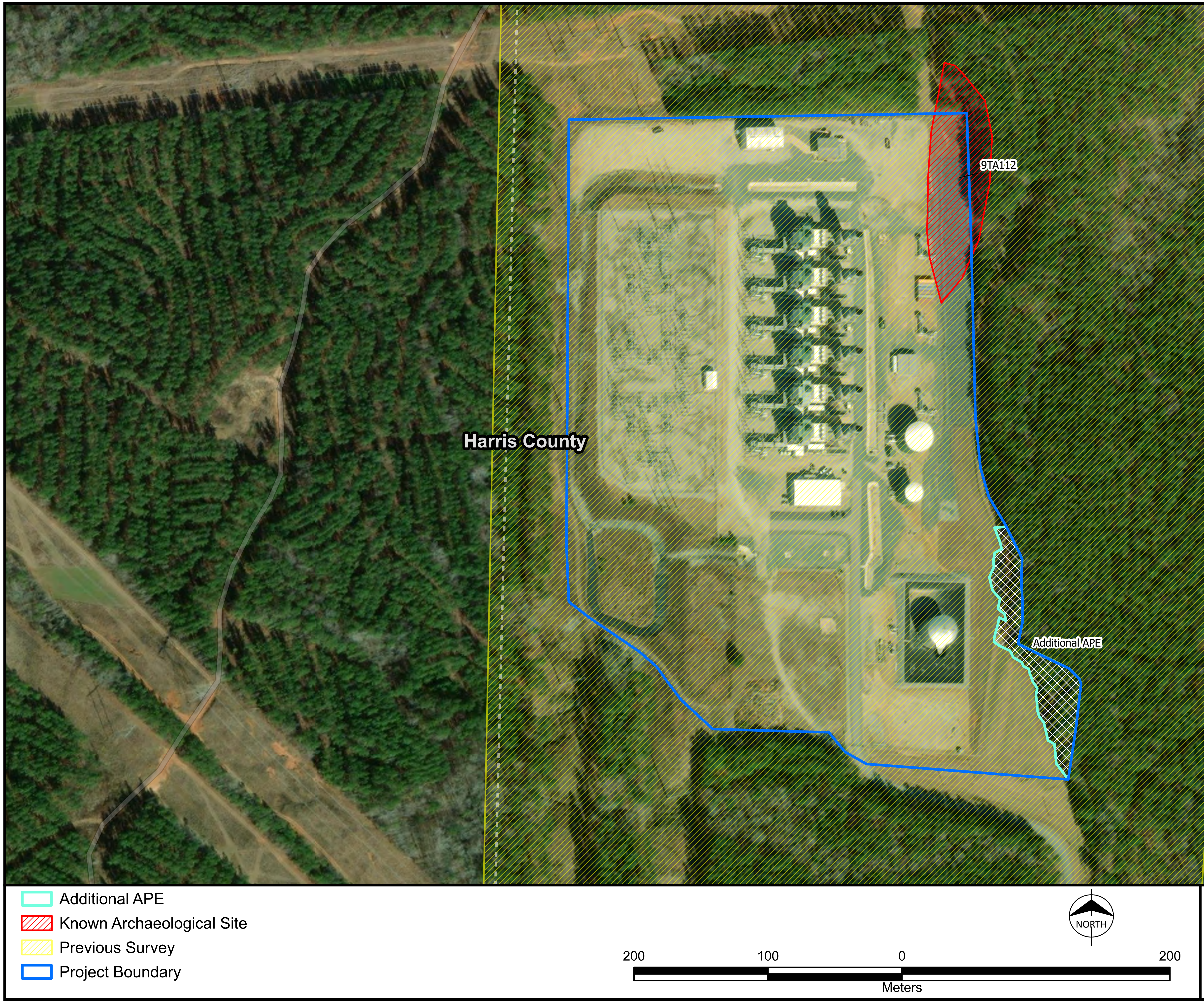

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

8/11/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Kristian Poncho
Tribal Historic Preservation Officer
Coushatta Tribe of Louisiana
1940 C.C. Bel Road
Elton, LA 70532

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Poncho:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Coushatta Tribe of Louisiana in Talbot County, Georgia. Should the Coushatta Tribe of Louisiana elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 9/11/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC kponcho@coushatta.org

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH
400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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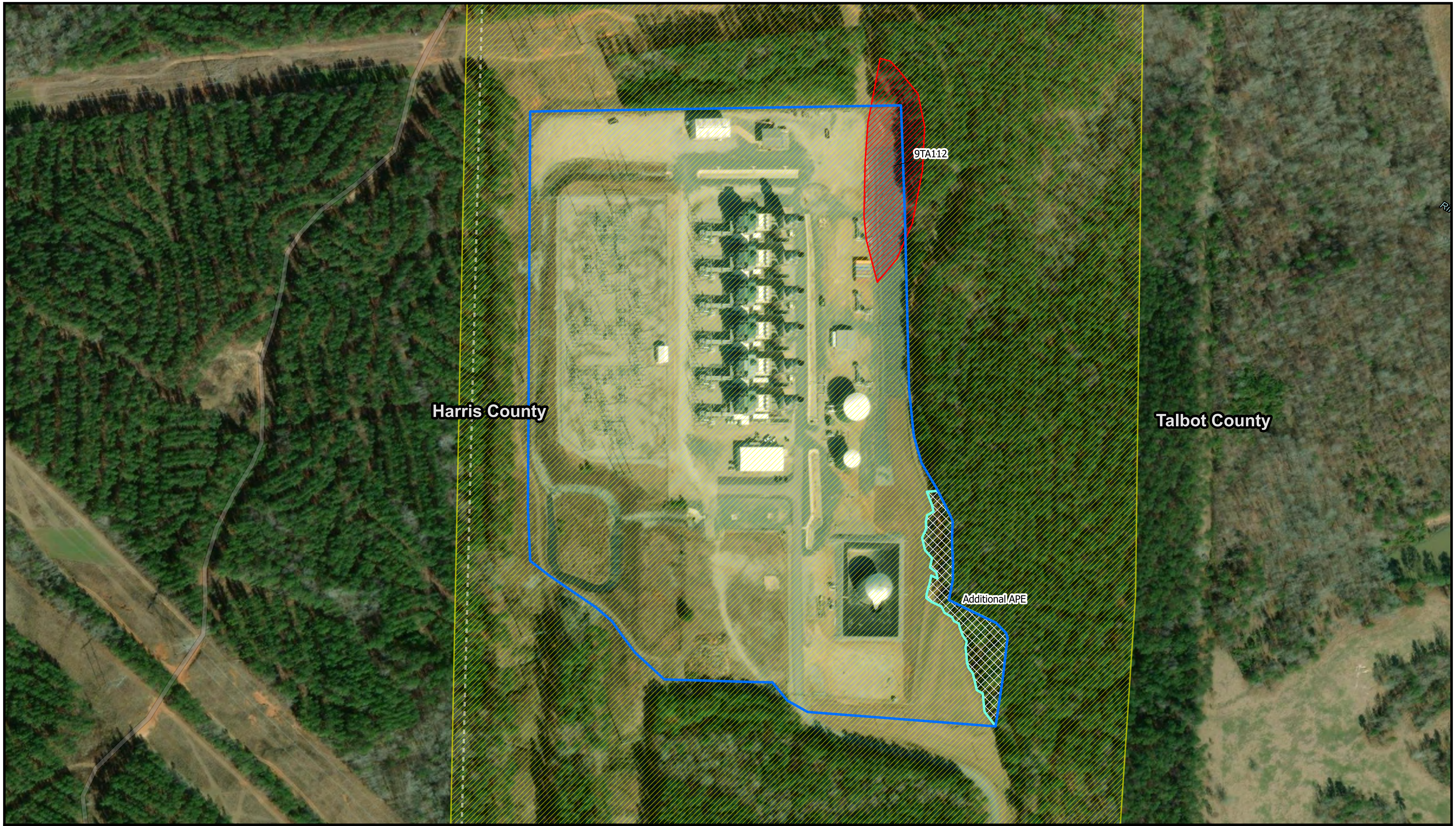

Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

USDA

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. David Cook
Tribal Administrator
Kialegee Tribal Town
P.O. Box 332
Wetumka, OK 74883

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Cook:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Kialegee Tribal Town in Talbot County, Georgia. Should the Kialegee Tribal Town elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC david.cook@kialegetribe.net

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

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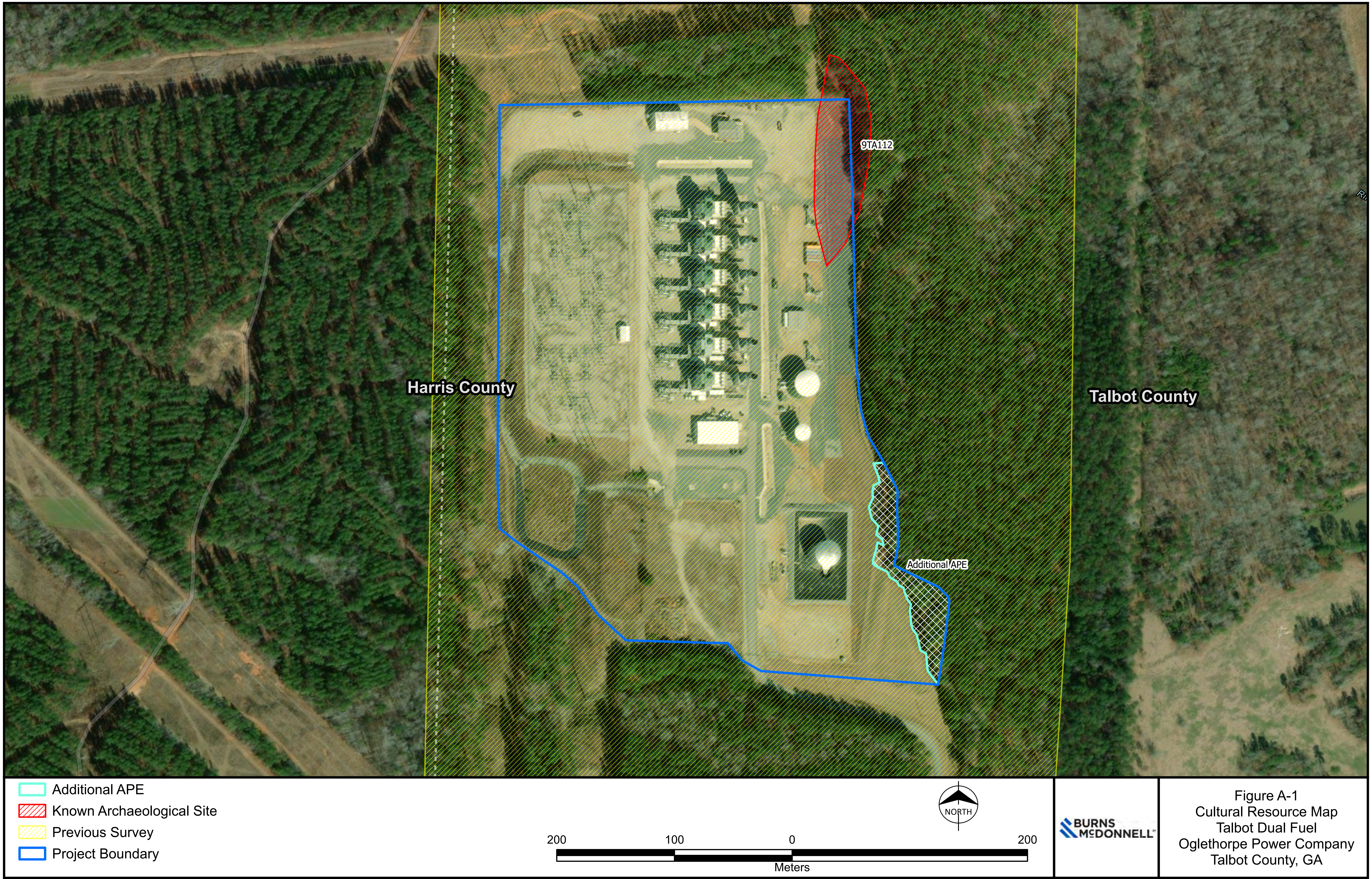

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Turner Hunt
Tribal Historic Preservation Officer
Muscogee (Creek) Nation
P.O. Box 580
Okmulgee, OK 74447

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Hunt:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Muscogee (Creek) Nation in Talbot County, Georgia. Should the Muscogee (Creek) Nation elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC section106@mcn-nsn.gov
thunt@muscogeenation.com

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

BURNS McDONNELL

Issued: 6/29/2023

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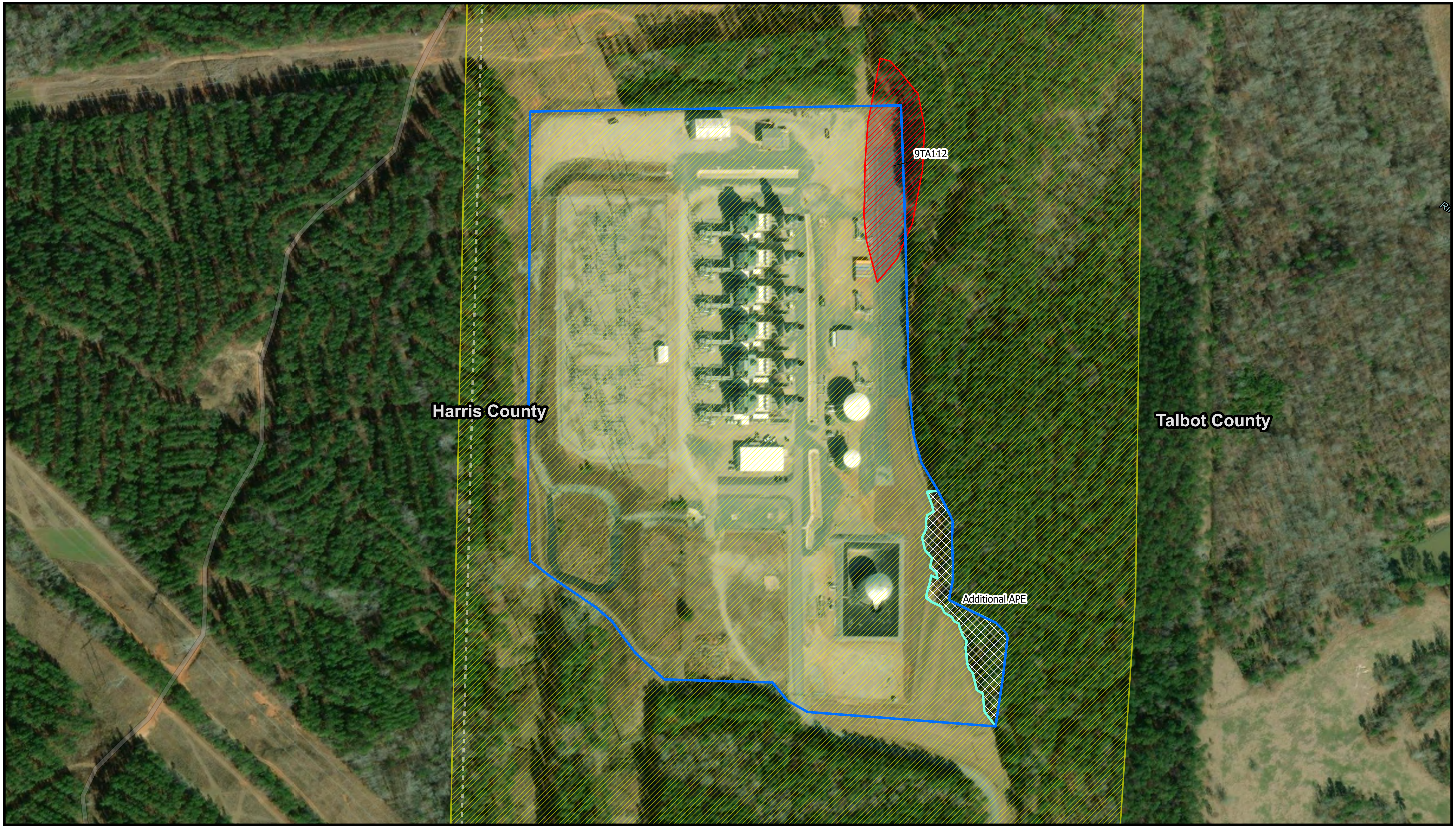
Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Randall Hicks
Council Representative
Muscogee (Creek) Nation National Council
P.O. Box 158
Okmulgee, OK 74447

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Hicks:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Muscogee (Creek) Nation National Council in Talbot County, Georgia. Should the Muscogee (Creek) Nation National Council elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.
If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC rhicks@mcnnc.com

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
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Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

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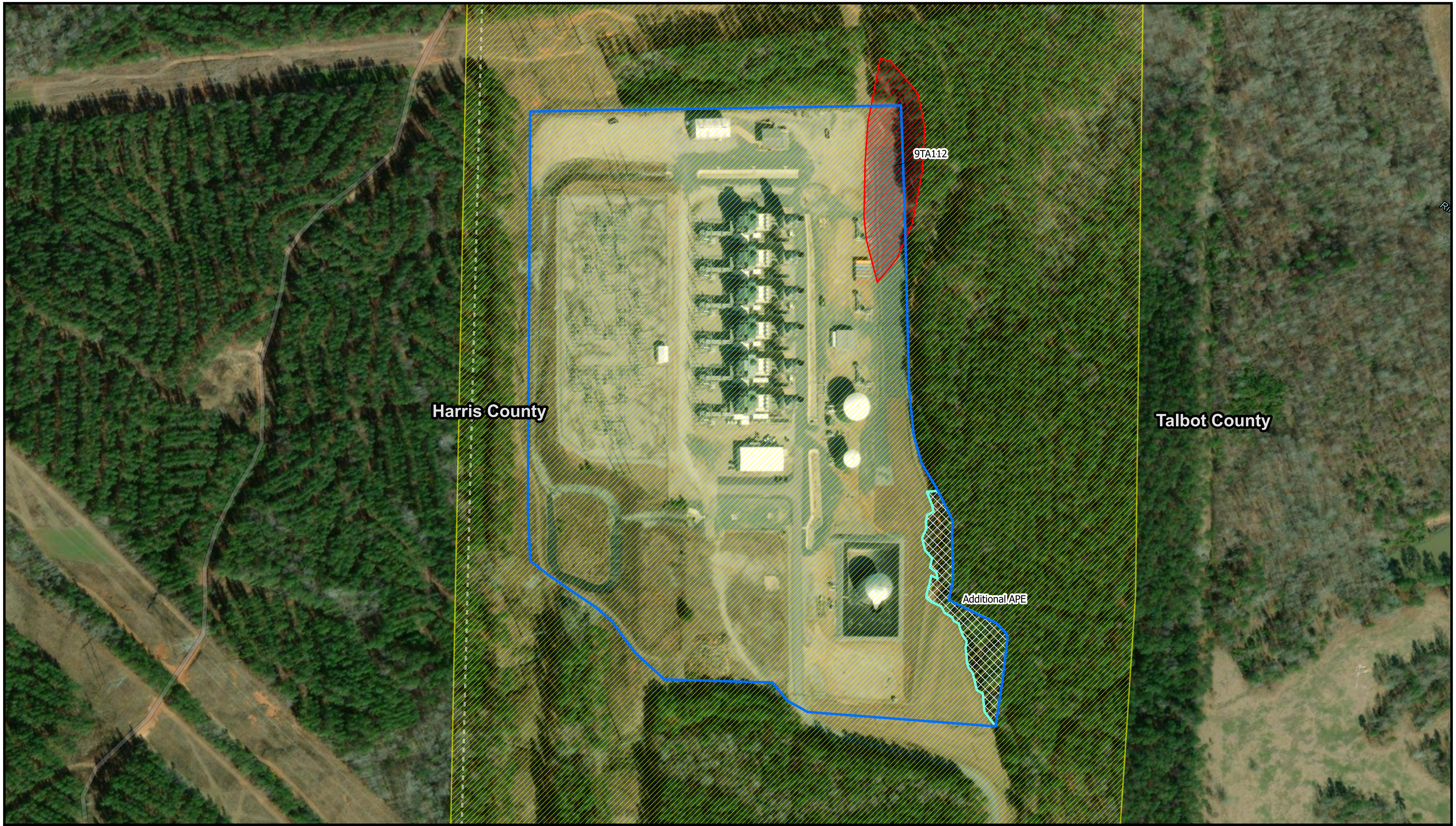

Additional APE
Known Archaeological Site
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Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Rural Development
Rural Utilities Service
1400 Independence
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Washington, DC,
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7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Larry Haikey
Tribal Historic Preservation Officer
Poarch Band of Creek Indians
5811 Jack Springs Road
Atmore, AL 36502

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Haikey:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

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new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Poarch Band of Creek Indians in Talbot County, Georgia. Should the Poarch Band of Creek Indians elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC lhaikey@pci-nsn.gov

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- Talbot Energy Facility
- Project Boundary
- Additional Clearing
- NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

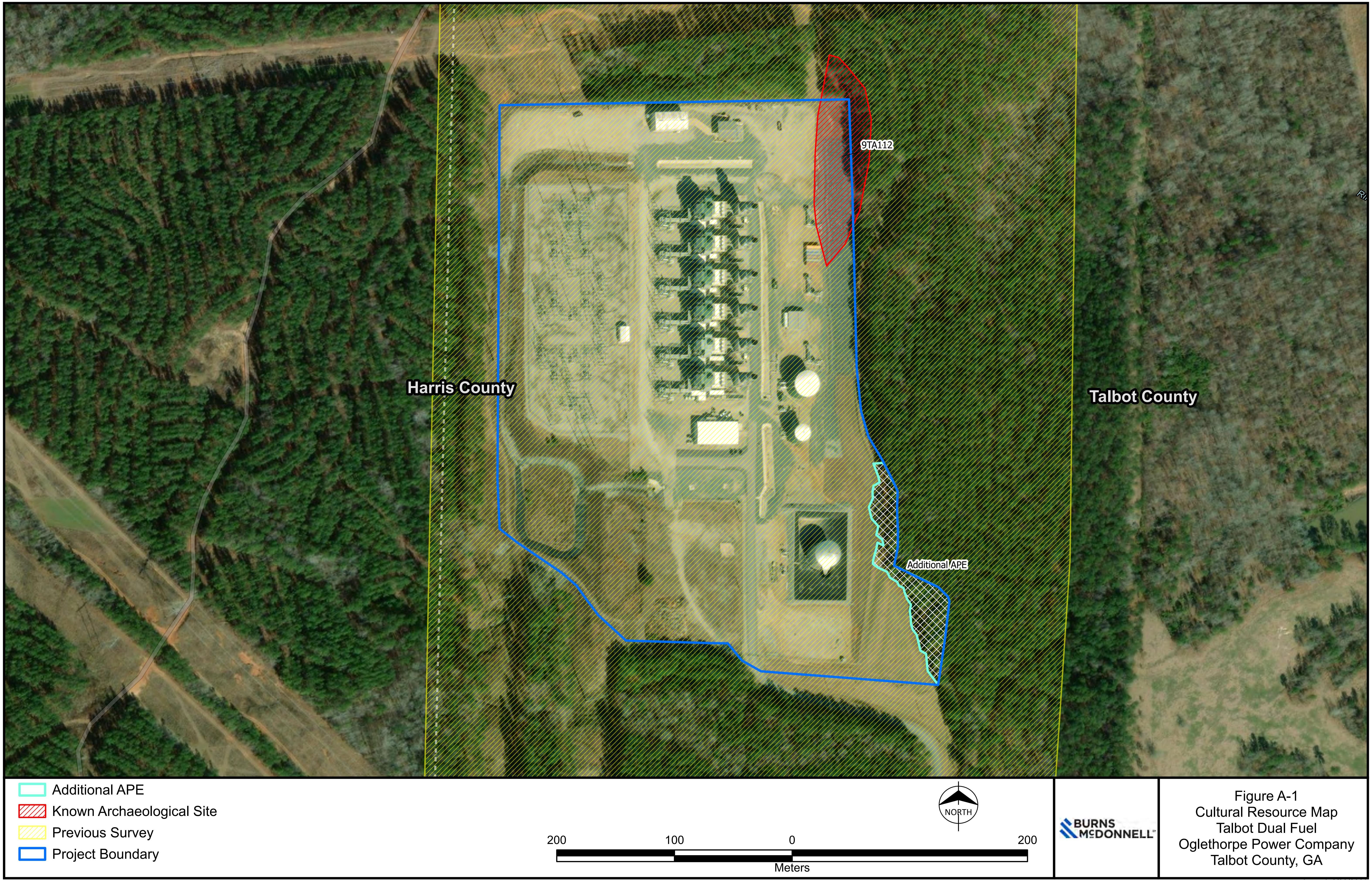

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

USDA

United States Department of Agriculture

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. Ben Yahola
Historic Preservation Officer
Seminole Nation of Oklahoma
P.O. Box 1498
Wewoka, OK 74884

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Yahola:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

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new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Seminole Nation of Oklahoma in Talbot County, Georgia. Should the Seminole Nation of Oklahoma elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC yahola.b@sno-nsn.gov

Talbot Energy Facility

Project Boundary

Additional Clearing

NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

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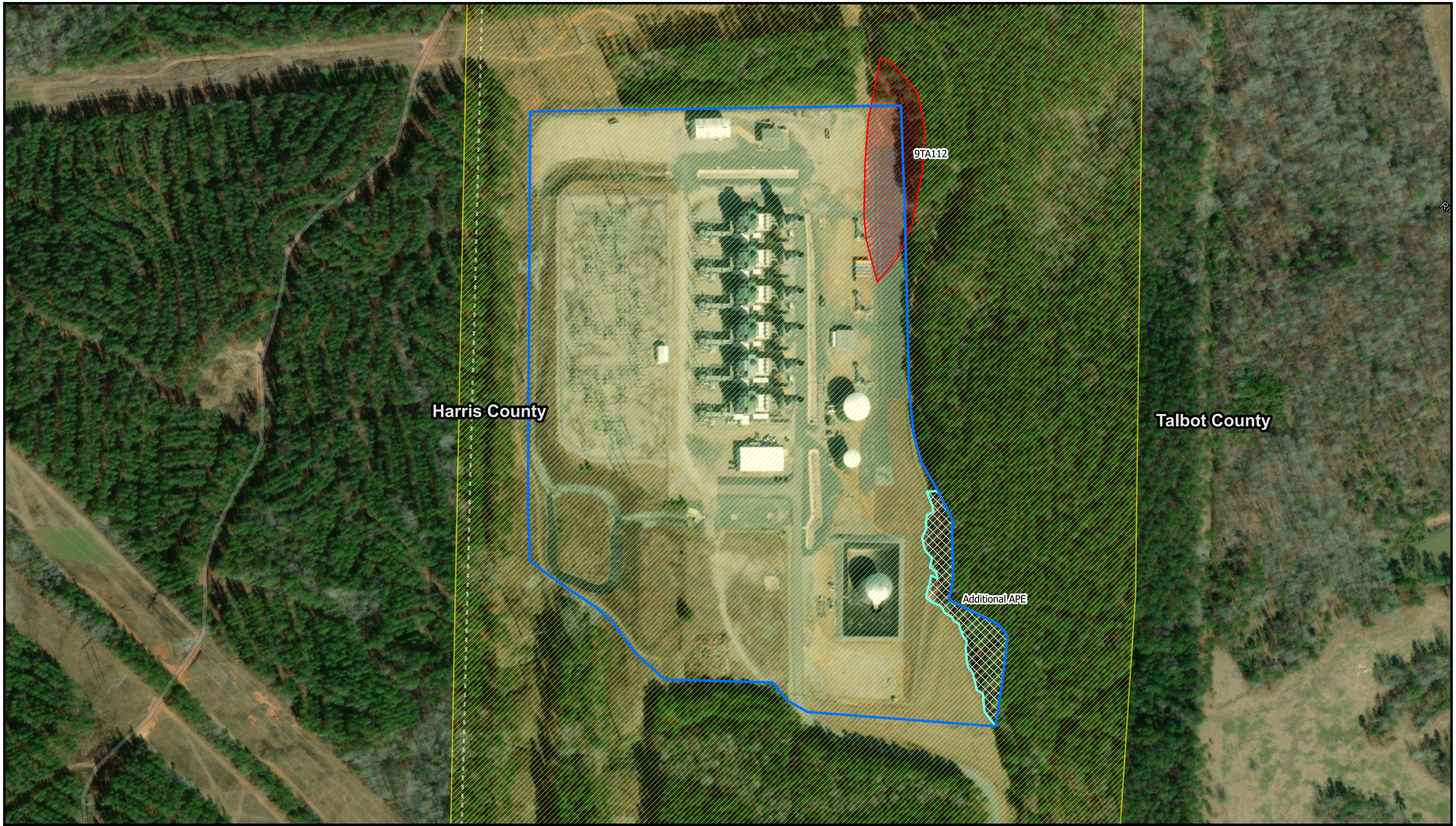
Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

USDA

United States Department of Agriculture

Rural Development
Rural Utilities Service
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Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Dr. Paul Backhouse
Sr. Director of the Heritage and Environment Resource Office
Seminole Tribe of Florida
30290 Josie Billie Hwy PMB 1004
Clewiston, FL 33440

Subject: United States Department of Agriculture (USDA) – Rural Development (RD) Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Dr. Backhouse:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

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Oglethorpe is notifying you about the referenced project because of the possible interest of the Seminole Tribe of Florida in Talbot County, Georgia. Should the Seminole Tribe of Florida elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

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Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC THPOCompliance@semtribe.com
paulbackhouse@semtribe.com

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

400 200 0 400
US Feet

NORTH

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
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Oglethorpe Power Corporation
Talbot County, GA

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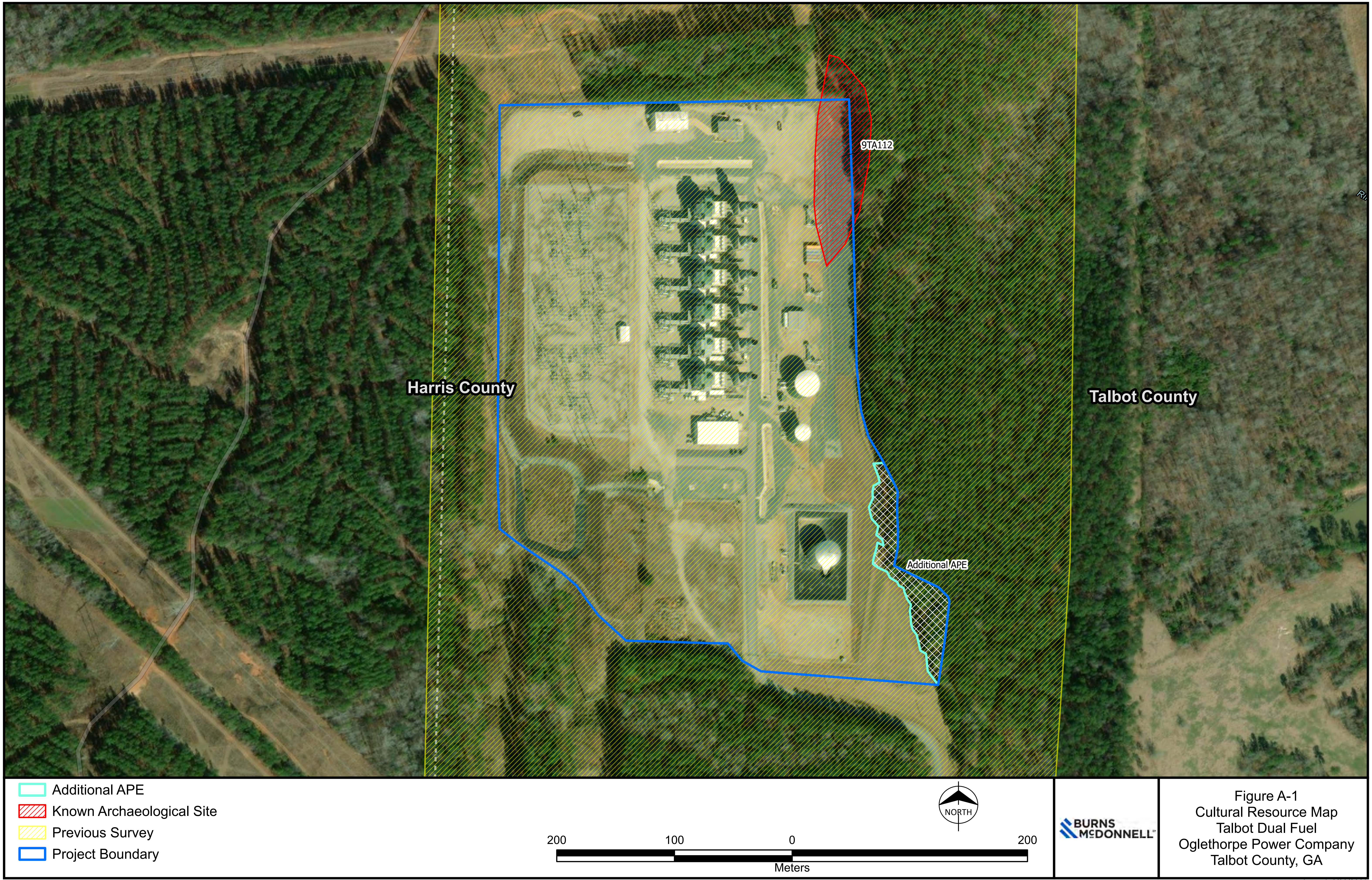

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

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Rural Utilities Service
1400 Independence Ave SW, Room 2230
Stop 1570,
Washington, DC, 20250
Voice 202.720.9540

7/10/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Mr. David Frank
Tribal Historic Preservation Officer
Thlopthlocco Tribal Town
P.O. Box 188
Okenah, OK 74859

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Frank:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, "Environmental Policies and Procedures" (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Thlopthlocco Tribal Town in Talbot County, Georgia. Should the Thlopthlocco Tribal Town elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 7/31/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC thpo@tttown.org

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

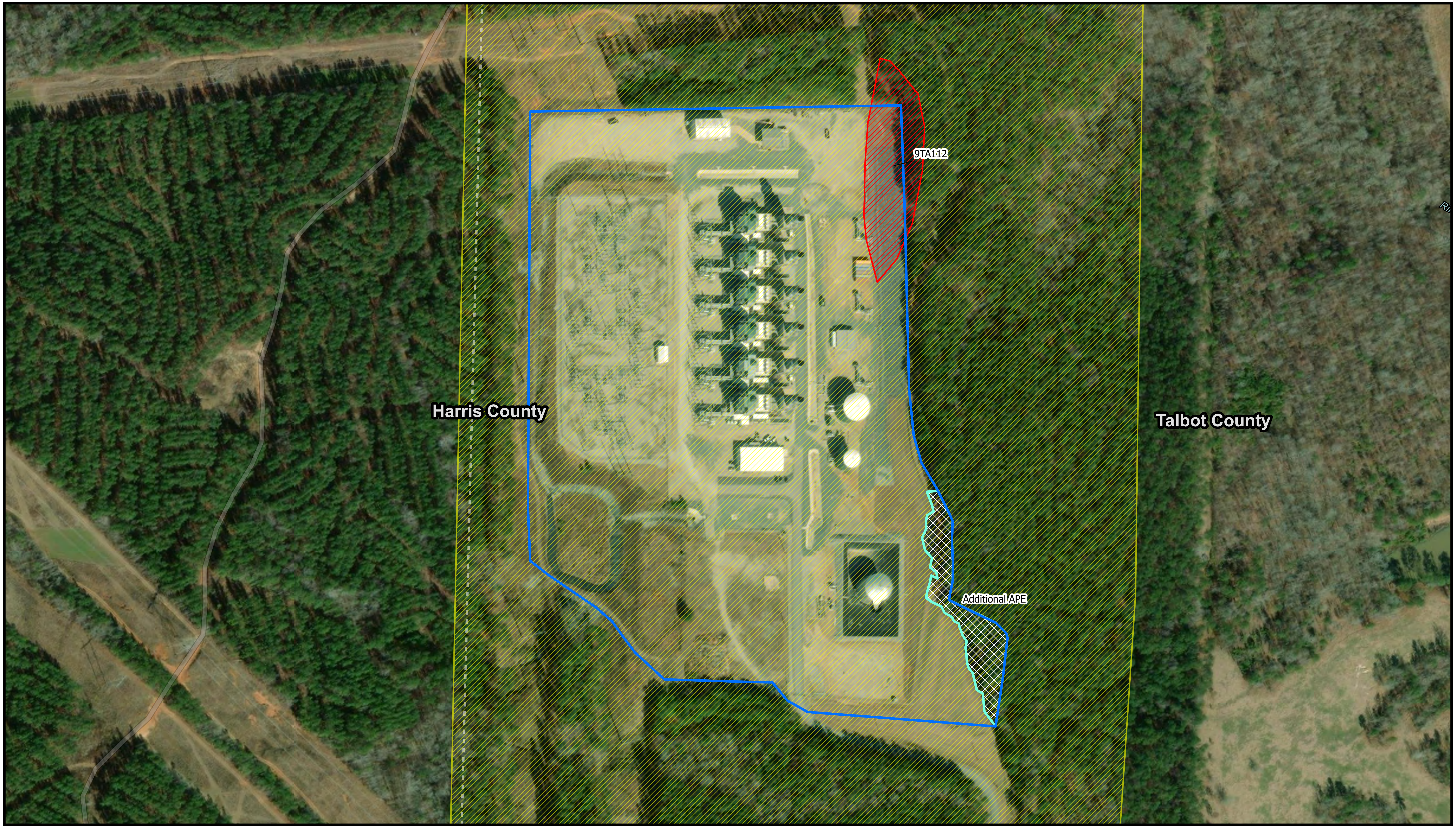
BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Ce



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Rural Development
Rural Utilities Service
1400 Independence
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Washington, DC,
20250
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08/08/2023

Gregory Korosec
Archaeologist
Rural Utilities Service, Rural Development, USDA
1400 Independence Ave. S.W.
Washington, DC 20250

Ms. Brina Williams
Tribal Historic Preservation Officer
c/o Alabama-Quassarte Tribal Town
P.O. Box 646
Okemah, OK 74859

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Applicant THPO Section 106 Initiation
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Ms. Williams:

Oglethorpe Power Corporation (Oglethorpe) plans to seek financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will be using the NPA to obligate funds before completing Section 106.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

new piping and infrastructure. No new combustion turbines will be constructed as part of the Project. A project location map and proposed site plan are enclosed for reference.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads, and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

Based on this definition, Oglethorpe proposes that the APE for the referenced project consists of the area within the existing footprint of the Facility and the approximately 0.85 acres proposed for clearing and grading, as shown on the enclosed map. The geographic scope of the APE will not be final until a determination is made by RUS pursuant to 36 CFR § 800.4(a)(1). Additionally, the APE does not include any federal and/or tribal lands as defined pursuant to 36 CFR § 800.16(x).

Pursuant to 36 CFR § 800.2(c)(4), and 7 CFR § 1970.5(b)(2) of the regulations, “Environmental Policies and Procedures” (7 CFR Part 1970), RUS has issued a blanket delegation for its applicants to initiate and proceed through Section 106 review if there is agreement.
In delegating this authority, RUS is advocating for the direct interaction between its RE Act program applicants and Indian tribes. RUS believes this interaction, prior to direct agency involvement, will support and encourage the consideration of impacts to historic properties of importance to Indian tribes earlier in project planning.

Oglethorpe is notifying you about the referenced project because of the possible interest of the Alabama-Quassarte Tribal Town in Talbot County, Georgia. Should the Alabama-Quassarte Tribal Town elect to participate in Section 106 review of the referenced project, please notify me in writing via letter or email as soon as possible at the following addresses – Sara Kent at sskent@burnsmcd.com or 4004 Summit Blvd., Ste. 1200, Atlanta, GA 30319.

Please include with your affirmative response, a description of any specific historic properties or important tribal resources in the APE and your recommendations about the level of effort needed to identify additional historic properties which might be affected by the referenced project. Oglethorpe will respect the confidentiality of the information which you provide to the fullest extent possible.

If at any time you wish to share your interests, recommendations and concerns directly with RUS, as the agency responsible for conducting Section 106 review, or to request that RUS participate directly in Section 106 review, please notify me at once, preferably via email. However, you may contact RUS directly. If you wish to do so, please submit your request to Greg Korosec at Gregory.Korosec@usda.gov.

Please submit your response **electronically** by 09/07/2023. RUS will proceed to the next step in Section 106 review if you fail to provide a timely response. Should you have any questions or require additional information you may contact me at the mailing address and email provided above.

Sincerely,

Gregory Korosec, PhD, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosure Attachment
CC brina.williams@alabama-quassarte.org
wilson.yargee@alabama-quassarte.org
aqhpo@mail.com

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400

US Feet

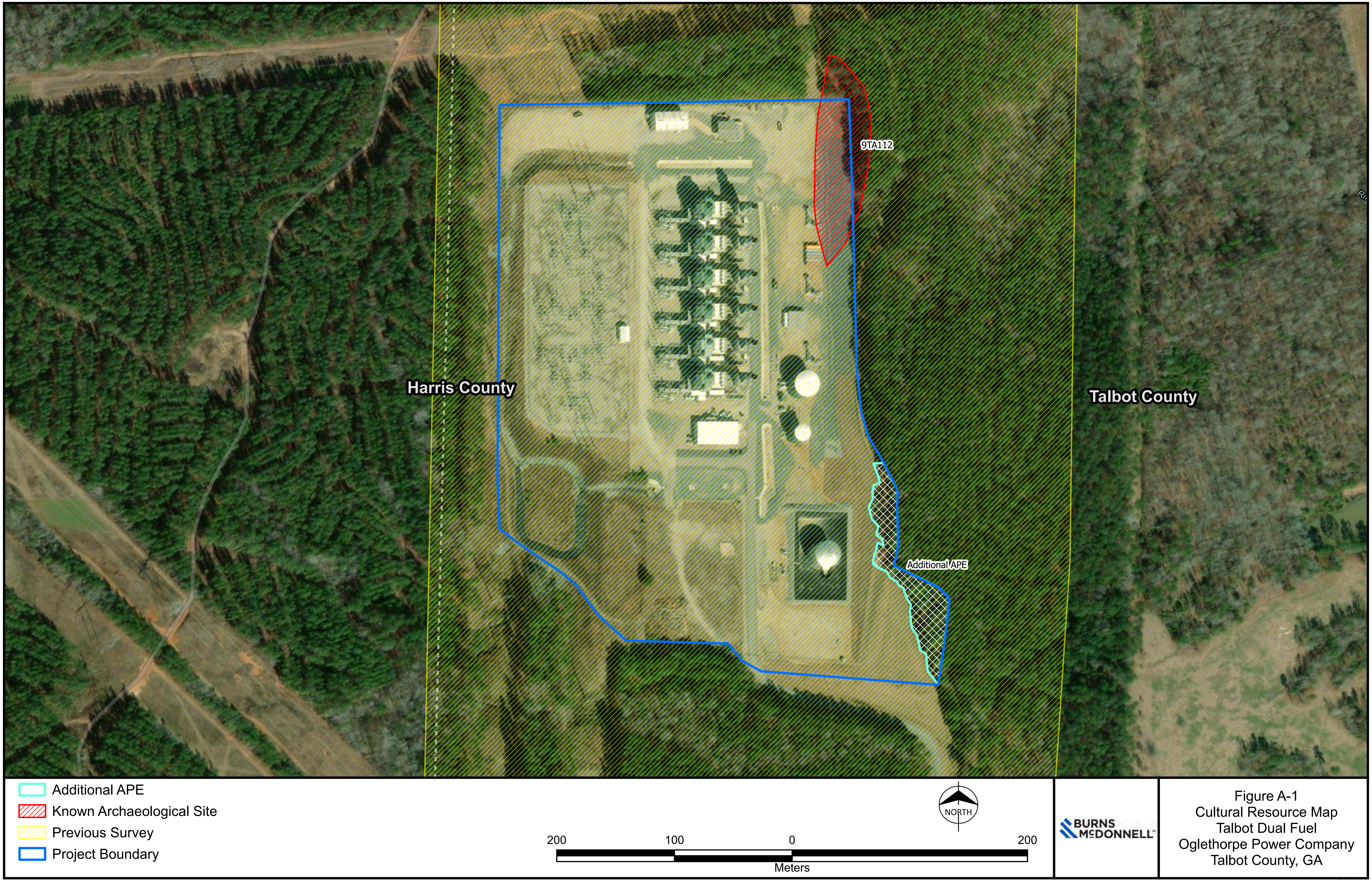
BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Cen



BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence
Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Alabama-Quassarte Tribal Town
P.O. Box 646
Okemah, OK 74859

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Tribal Leader:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Alabama-Quassarte Tribal Town. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,
KRISTEN BASTIS
Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:13:38 -04'00'
Kristen Bastis, MA, RPA
Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

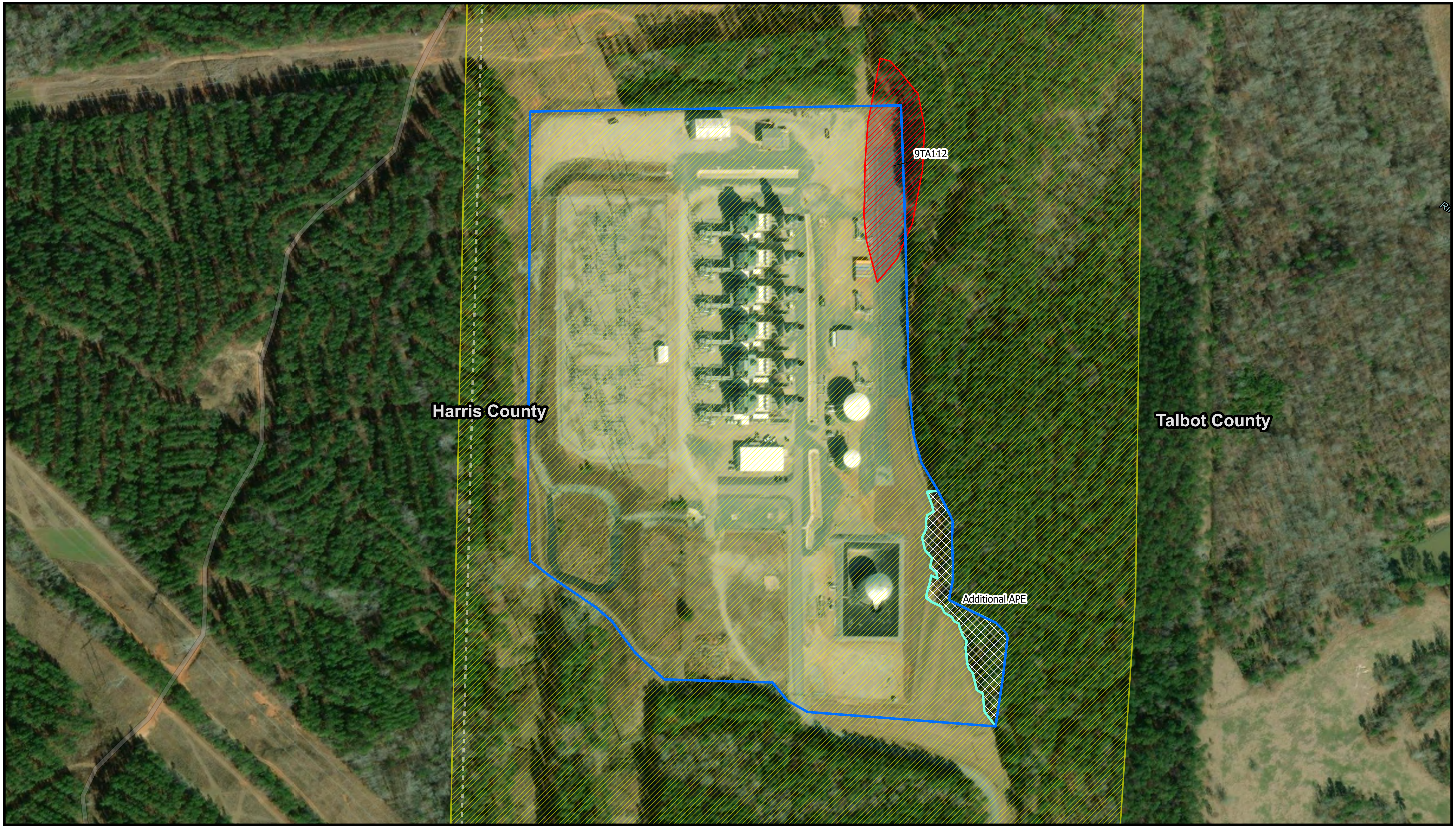
NORTH
400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

**THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.**

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs   County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant**   X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556   Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662   Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ______________________

B. **Project Description and Plans** This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1. Farming	YES ____	NO ____
2. Pasture	YES ____	NO ____
3. Mining	YES ____	NO ____
4. Timbering	YES _X_	NO ____
5. Road construction	YES ____	NO ____
6. Housing	YES ____	NO ____
7. Landfill	YES ____	NO ____
8. Commercial	YES ____	NO ____
9. Industrial	YES ____	NO ____
10. Other (explain): ___________________________		

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	***Then your APE would be...***
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?

YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?

YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?

YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
   If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
   If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
   If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - In urban areas, please also include a city map that shows more detail
  - Boundaries of the APE as noted in section II above
  - Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - Detailed scope of work
  - Site plans (before and after)
  - Project plans
  - Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - Location of all photographs by photo number
  - Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

HPD no longer accepts project materials for review via mail, with the exception of archival mitigation documentation, as applicable.

[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

USDA
United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Mr. Kristian Poncho
Tribal Historic Preservation Officer
Coushatta Tribe of Louisiana
1940 C.C. Bel Road
Elton, LA 70532

Subject: United States Department of Agriculture (USDA) – Rural Development (RD) Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Poncho:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Coushatta Tribe of Louisiana. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:49:58 -04'00'

Kristen Bastis, MA, RPA
Archeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Cen

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

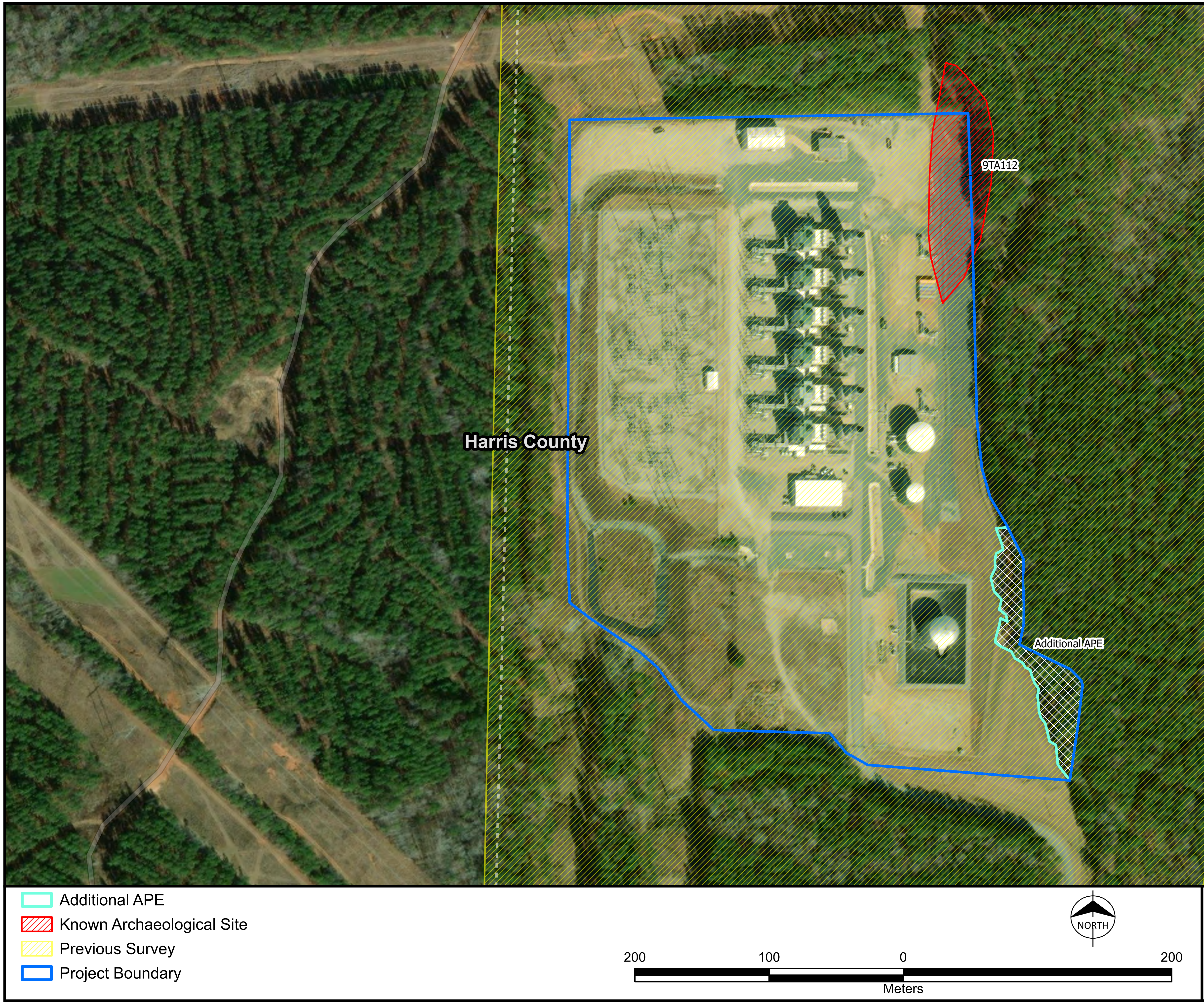


Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
****If yes, please enclose a copy of HPD's previous response***

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____
10.	Other (explain): ____________________________		

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO_____ DO NOT KNOW_____(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	*Then your APE would be...*
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - o Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - o Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - o In urban areas, please also include a city map that shows more detail
  - o Boundaries of the APE as noted in section II above
  - o Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - o Detailed scope of work
  - o Site plans (before and after)
  - o Project plans
  - o Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - o The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - o Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - o If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
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  - o Location of all photographs by photo number
  - o Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

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United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Mr. David Cook
Tribal Administrator
Kialegee Tribal Town
P.O. Box 332
Wetumka, OK 74883

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Administrator Cook:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

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[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

If RUS elects to fund the Project, it will become an undertaking subject to review under Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Kialegee Tribal Town. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:47:42 -04'00'

Kristen Bastis, MA, RPA

Archeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

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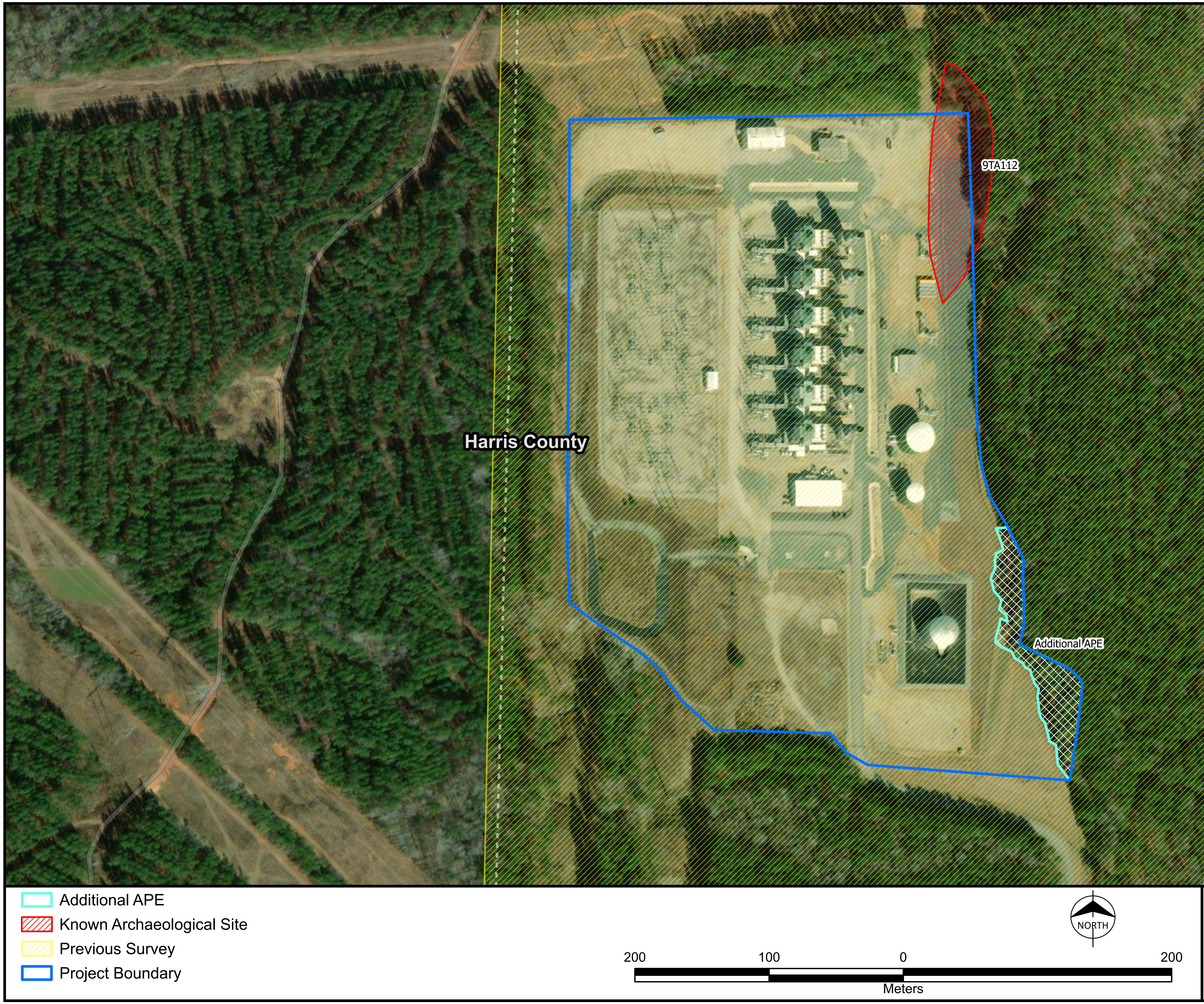
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Ce



BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ______________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

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Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
**If yes, are project plans/scope of work available yet?* YES _X___ NO ____
If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____
10.	Other (explain): ___________________________		

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	***Then your APE would be...***
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

   If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
   ***If yes, please explain:** _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
   ***If yes, please explain:** _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
   ***If yes, please explain:** _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - In urban areas, please also include a city map that shows more detail
  - Boundaries of the APE as noted in section II above
  - Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - Detailed scope of work
  - Site plans (before and after)
  - Project plans
  - Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - Location of all photographs by photo number
  - Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

HPD no longer accepts project materials for review via mail, with the exception of archival mitigation documentation, as applicable.

[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

USDA

United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence
Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Mr. Turner Hunt
Tribal Historic Preservation Officer
Muscogee (Creek) Nation
P.O. Box 580
Okmulgee, OK 74447

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Hunt:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered “direct” regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). “Indirect” effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Muscogee (Creek) Nation. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,
KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:30:36 -04'00'

Kristen Bastis, MA, RPA

Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

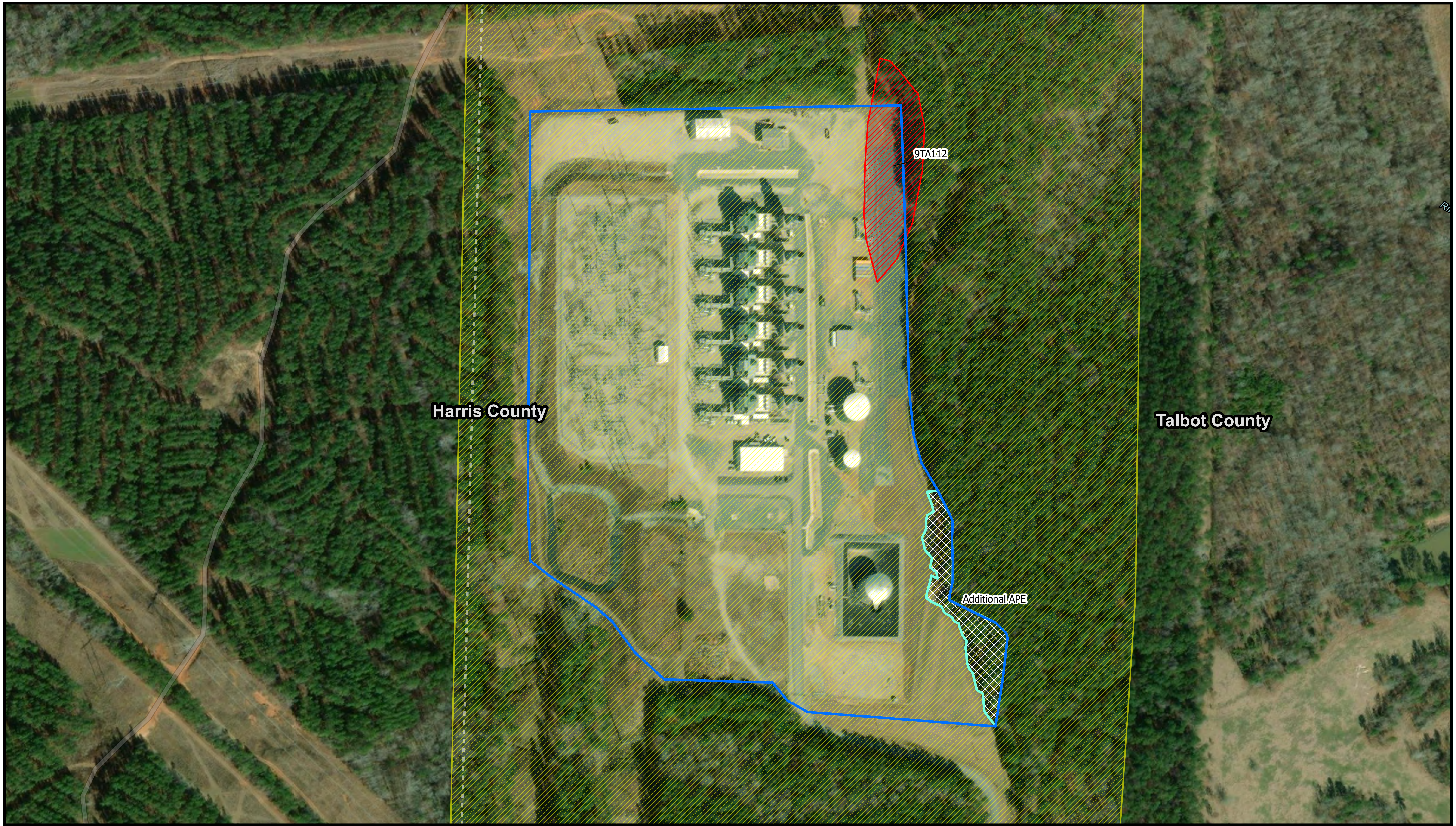
400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X____ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____

10. Other (explain): ____________________________

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	***Then your APE would be...***
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

   If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
   If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
   If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
   If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - o Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - o Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
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  - o Boundaries of the APE as noted in section II above
  - o Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
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  - o Site plans (before and after)
  - o Project plans
  - o Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
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  - o Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
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  - o *****Google Street view and publicly available Tax Assessor images will not be accepted***
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  - o Direction of view for all photographs
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10/10/2023

Rural Development
Rural Utilities Service
1400 Independence
Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Mr. Larry Haikey
Tribal Historic Preservation Officer
Poarch Band of Creek Indians
5811 Jack Springs Road
Atmore, AL 36502

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Haikey:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Poarch Band of Creek Indians. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:33:22 -04'00'

Kristen Bastis, MA, RPA

Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400

US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023

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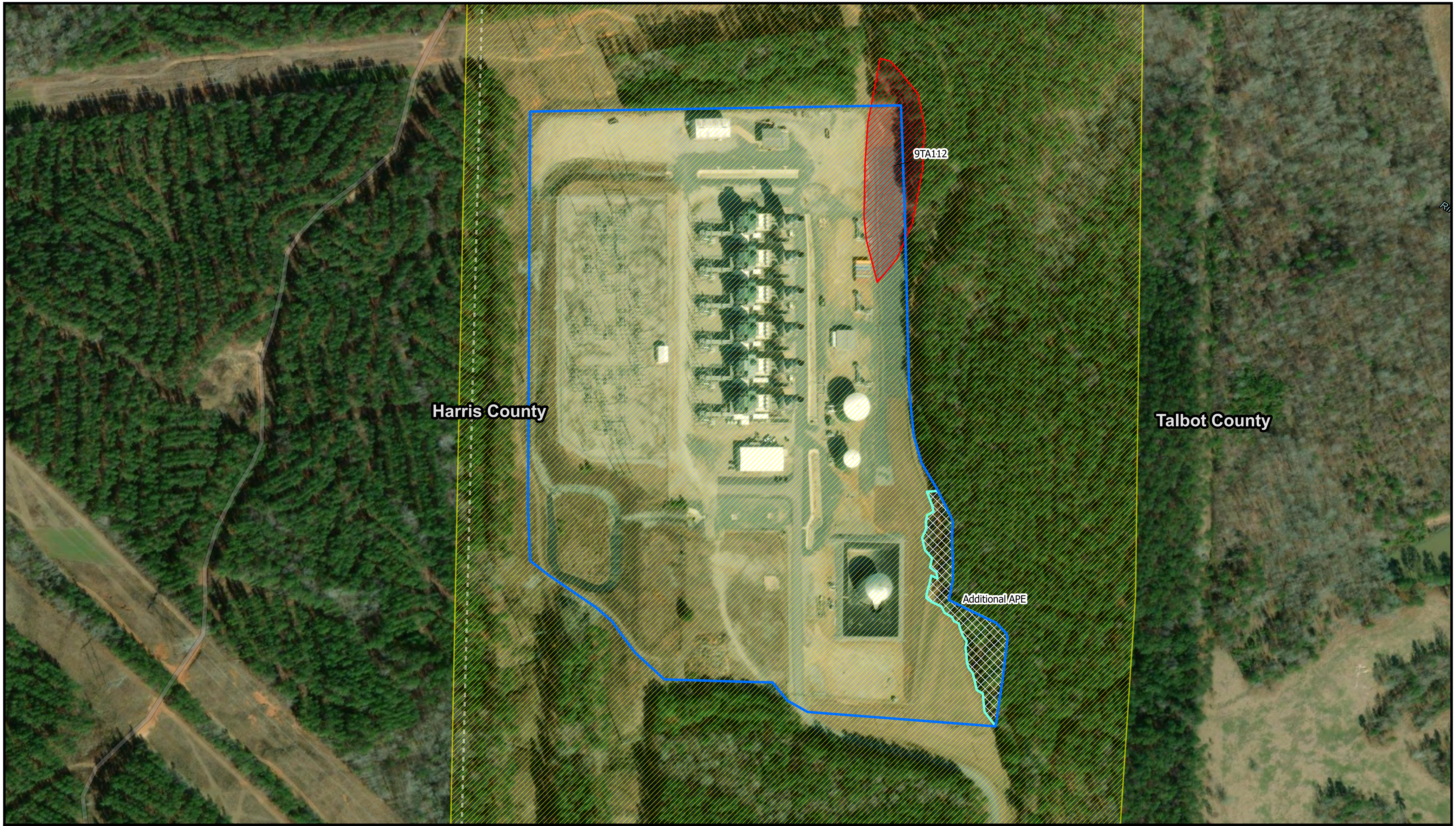
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Ce



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

- X Funding (grant, loan, etc.)
- ☐ License/Permit
- ☐ Direct/Agency is performing the action
- ☐ Unknown
- ☐ Other, please explain: ______________________________

D. Type of Review Requested:

- X Section 106 of the National Historic Preservation Act (Federal agency involvement)
- ☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
- ☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
- ☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
- ☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____
10.	Other (explain): ____________________________		

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	*Then your APE would be...*
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

   If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
   If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
   If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
   If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - o Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - o Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - o In urban areas, please also include a city map that shows more detail
  - o Boundaries of the APE as noted in section II above
  - o Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - o Detailed scope of work
  - o Site plans (before and after)
  - o Project plans
  - o Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - o The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - o Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - o If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - o *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - o Location of all photographs by photo number
  - o Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

HPD no longer accepts project materials for review via mail, with the exception of archival mitigation documentation, as applicable.

[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

USDA
United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 4018
Stop 1570,
Washington, DC, 20250
Voice 202.870.6512

Mr. Ben Yahola
Historic Preservation Officer
Seminole Nation of Oklahoma
P.O. Box 1498
Wewoka, OK 74884

Subject: United States Department of Agriculture (USDA) – Rural Development (RD) Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Yahola:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Seminole Nation of Oklahoma. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:36:28 -04'00'

Kristen Bastis, MA, RPA

Archaeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

★ Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

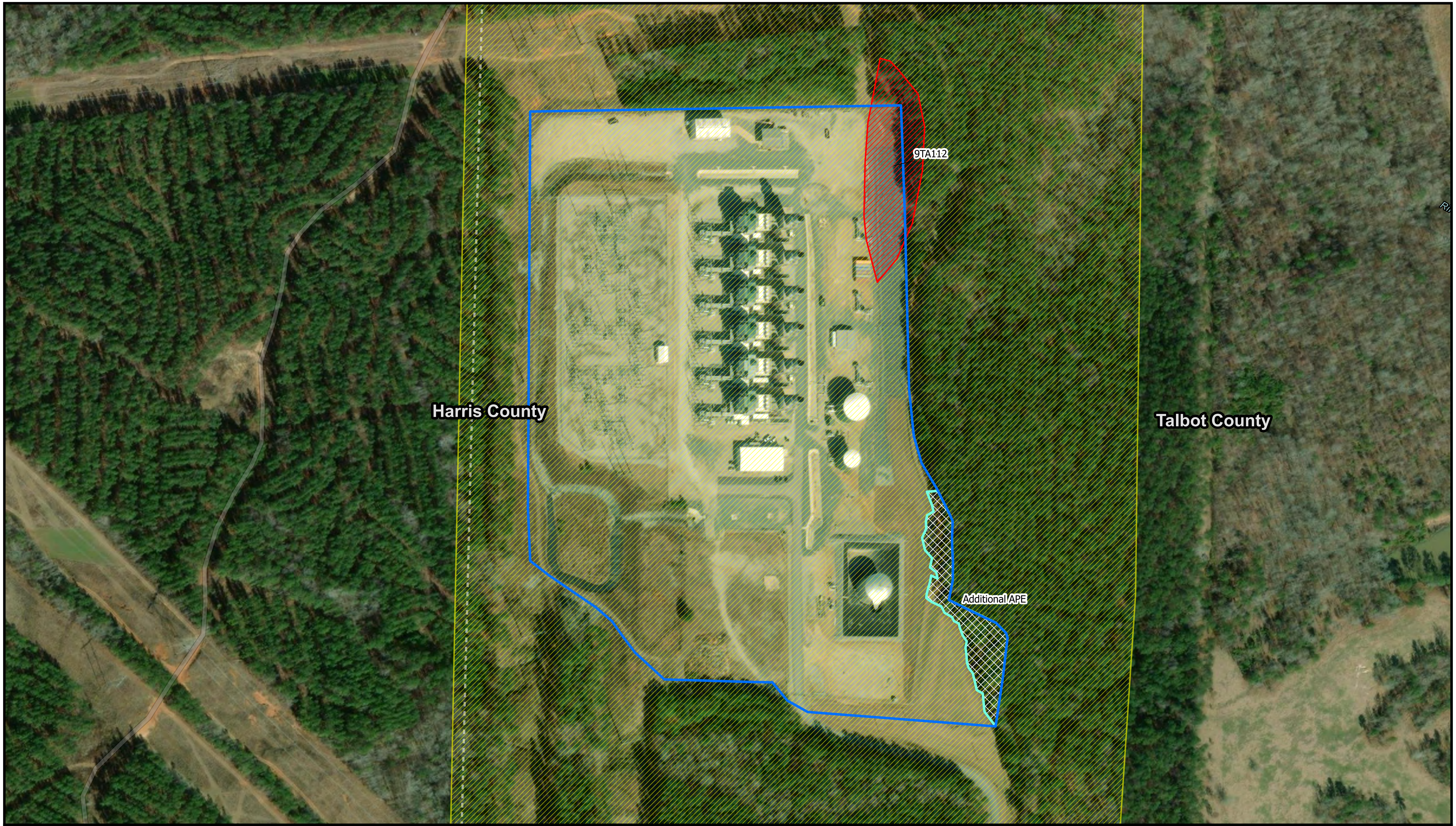
BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Cen

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

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THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
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☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

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D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1. Farming YES ____ NO ____
2. Pasture YES ____ NO ____
3. Mining YES ____ NO ____
4. Timbering YES _X_ NO ____
5. Road construction YES ____ NO ____
6. Housing YES ____ NO ____
7. Landfill YES ____ NO ____
8. Commercial YES ____ NO ____
9. Industrial YES ____ NO ____
10. Other (explain): ____________________________

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

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If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

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If your project includes...	***Then your APE would be...***
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C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
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If yes, please identify the properties (by name or photo #).

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1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

   If yes, please explain: _N/A____

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   If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
   If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
   If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - In urban areas, please also include a city map that shows more detail
  - Boundaries of the APE as noted in section II above
  - Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - Detailed scope of work
  - Site plans (before and after)
  - Project plans
  - Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - Location of all photographs by photo number
  - Direction of view for all photographs
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[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence Ave SW, Room 4018
Stop 1570,
Washington, DC, 20250
Voice 202.870.6512

Dr. Paul Backhouse
Sr. Director of the Heritage and Environment Resource Office
Seminole Tribe of Florida
30290 Josie Billie Hwy PMB 1004
Clewiston, FL 33440

Subject: United States Department of Agriculture (USDA) – Rural Development (RD) Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Dr. Backhouse:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

Oglethorpe is responsible for providing reliable, efficient, and low-cost power to the 38 EMC members of the not-for-profit generation cooperative who provide power to over 4 million Georgians. The proposed Project would increase reliability at the existing Facility in the event natural gas is curtailed or cut-off in times of heavy loads and allow Oglethorpe to meet system demand with the Facility operating its existing units rather than starting other less efficient units, purchasing power from others, or constructing or obtaining new generation.

If RUS elects to fund the Project, it will become an undertaking subject to review under

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

The APE for the referenced project consists of the area within the existing footprint of the Facility, as shown on the enclosed map. Additionally, the APE does not include any federal and/or tribal lands as de-fined pursuant to 36 CFR § 800.16(x).

On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Seminole Tribe of Florida. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:44:10 -04'00'

Kristen Bastis, MA, RPA

Archeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Issued: 6/29/2023

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Cen

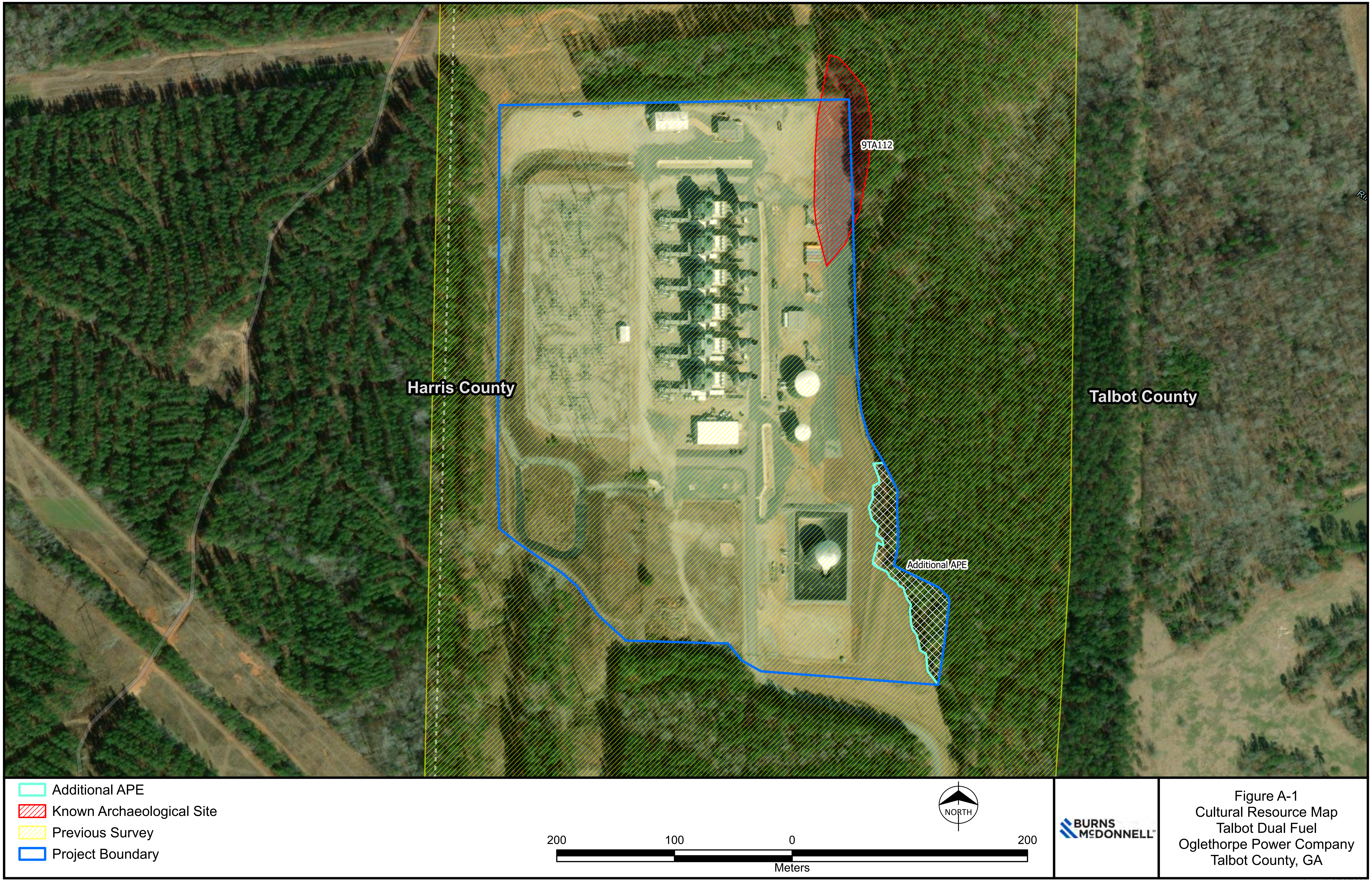

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

**THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.**

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs   County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant**   X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556   Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662   Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ______________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1. Farming	YES ____	NO ____
2. Pasture	YES ____	NO ____
3. Mining	YES ____	NO ____
4. Timbering	YES _X_	NO ____
5. Road construction	YES ____	NO ____
6. Housing	YES ____	NO ____
7. Landfill	YES ____	NO ____
8. Commercial	YES ____	NO ____
9. Industrial	YES ____	NO ____

10. Other (explain): ___________________________

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	*Then your APE would be...*
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_

If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_

If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_

If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - In urban areas, please also include a city map that shows more detail
  - Boundaries of the APE as noted in section II above
  - Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - Detailed scope of work
  - Site plans (before and after)
  - Project plans
  - Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - Location of all photographs by photo number
  - Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

HPD no longer accepts project materials for review via mail, with the exception of archival mitigation documentation, as applicable.

[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

USDA
United States Department of Agriculture

10/10/2023

Rural Development
Rural Utilities Service
1400 Independence
Ave SW, Room 4018
Stop 1570,
Washington, DC,
20250
Voice 202.870.6512

Mr. David Frank
Tribal Historic Preservation Officer
Thlopthlocco Tribal Town
P.O. Box 188
Okenah, OK 74859

Subject: United States Department of Agriculture (USDA) – Rural Development (RD)
Rural Utilities Services (RUS) Recommended Finding of No Historic Properties Affected
Oglethorpe Power Corporation
Talbot Energy Facility Dual Fuel Conversion Project
9125 Cartledge Road, Box Springs, Talbot County, Georgia

Dear Mr. Frank:

Oglethorpe Power Corporation (Oglethorpe) is seeking financial assistance from the USDA Rural Development (RD), Rural Utilities Service (RUS) under its Rural Electrification Act (RE Act) for the Talbot Energy Facility Dual Fuel Conversion Project (Project). This Project will not be using the NPA.[1]

Oglethorpe owns and operates six units at the Talbot Energy Facility located at 9125 Cartledge Road in Box Springs, Georgia (Facility). Oglethorpe is proposing to construct new infrastructure within the existing footprint of the Facility to provide the ability to use diesel fuel as an alternative fuel source in four of the Facility's six existing natural gas-fired combustion turbines for maintaining plant operations and improving reliability. The proposed infrastructure would include a new aboveground diesel fuel oil storage tank, new aboveground demineralized water storage tanks, and associated new piping and infrastructure. No new combustion turbines will be constructed as part of the Project.

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If RUS elects to fund the Project, it will become an undertaking subject to review under

[1] *Nationwide Programmatic Agreement among the U.S. Department of Agriculture Rural Development Programs, National Conference of State Historic Preservation Officers, Tribal Signatories, and The Advisory Council on Historic Preservation for Sequencing Section 106* (NPA).

Section 106 of the National Historic Preservation Act, 54 U.S.C. 306108, and its implementing regulations, 36 CFR Part 800.

RUS defines the area of potential effect (APE), as an area that includes all Project construction and excavation activity required to construct, modify, improve, or maintain any facilities; any right-of-way or easement areas necessary for the construction, operation, and maintenance of the Project; all areas used for excavation of borrow material and habitat creation; all construction staging areas, access routes, utilities, spoil areas, and stockpiling areas. Impacts that come from the undertaking at the same time and place with no intervening causes, are considered "direct" regardless of its specific type (e.g., whether it is visual, physical, auditory, etc.). "Indirect" effects to historic properties are those caused by the undertaking that are later in time or farther removed in distance but are still reasonably foreseeable.

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On 7/10/2023 the following Indian tribes were notified about the Talbot Energy Facility Dual Fuel Conversion Project: Alabama-Coushatta Tribe of Texas, Alabama-Quassarte Tribal Town, Muscogee (Creek) Nation, Muscogee (Creek) Nation National Council, Poarch Band of Creek Indians, Seminole Nation of Oklahoma, Thlopthlocco Tribal Town, Coushatta Tribe of Louisiana, Kialegee Tribal Town, and Seminole Tribe of Florida. No response to the notification was received from the Indian tribes.

The enclosed document titled, Georgia Historic Preservation Division (SHPO) Environmental Review Form describes the results of the investigation of the APE. While archaeological sites have been documented within one mile of the APE, none are within the APE. Based on the findings of the Environmental Review Form, a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) is appropriate for the referenced project.

Accordingly, the RUS is submitting a finding of no historic properties affected in accordance with 36 CFR § 800.4(d)(1) and supporting documentation for review and consideration by the Thlopthlocco Tribal Town. Please provide your concurrence or objection **electronically** within 30 days of your receipt of this recommended finding. In accordance with 36 CFR § 800.3(c)(4), RUS will proceed to the next step in review if we do not receive a response from you within thirty days. Please direct any questions you may have to Kristen Bastis at Kristen.Bastis@usda.gov.

Sincerely,

KRISTEN BASTIS

Digitally signed by KRISTEN BASTIS
Date: 2023.10.10 10:42:05 -04'00'

Kristen Bastis, MA, RPA

Archeologist
Rural Utilities Service, Rural Development, USDA

Enclosures

Project Map
GA SHPO Project Review Form

Path: C:\ATL_ENS_Projects\Effingham Energy Facility_Oglethorpe_20220929_BU\Effingham Energy Facility_Oglethorpe_20220929_BU.aprx bouruowhe 6/29/2023
Service Layer Credits: Hybrid Reference Layer: Esri Community Maps Contributors, Columbus Consolidated Government, © OpenStreetMap, Microsoft, Esri, HERE, Garmin, SafeGraph, GeoTechnologies, Inc, METI/NASA, USGS, EPA, NPS, US Ce

Talbot Energy Facility
Project Boundary
Additional Clearing
NHD Flowline

NORTH

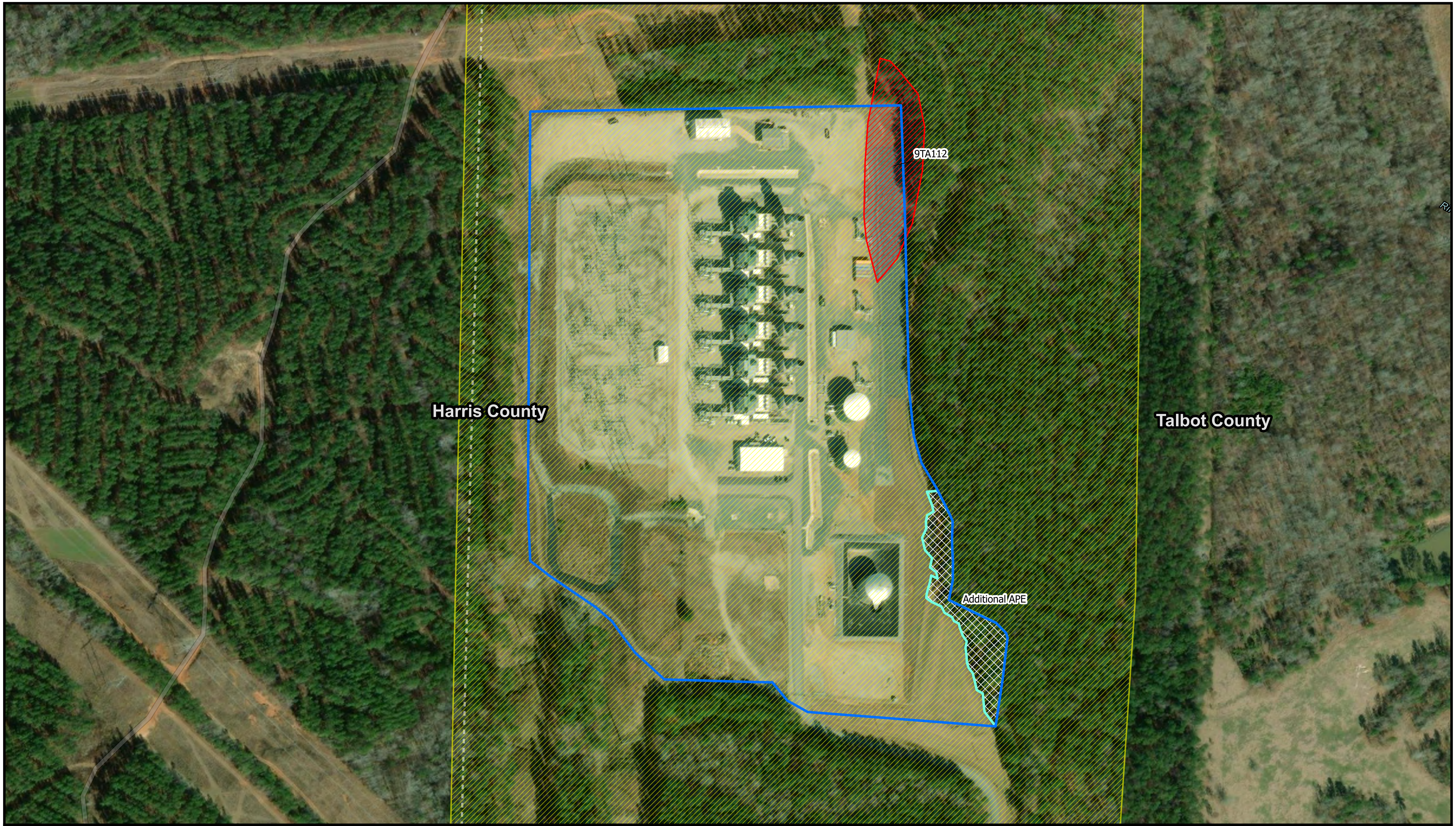
400 200 0 400
US Feet

BURNS McDONNELL

Project Location Map
Oglethorpe Power
Talbot Energy Facility,
Dual Fuel Conversion Project
Oglethorpe Power Corporation
Talbot County, GA

Source: Esri, USGS, NHD, NWI, Oglethorpe Power Corporation, and Burns & McDonnell

Issued: 6/29/2023



Additional APE
Known Archaeological Site
Previous Survey
Project Boundary

NORTH

200 100 0 200
Meters

BURNS McDONNELL

Figure A-1
Cultural Resource Map
Talbot Dual Fuel
Oglethorpe Power Company
Talbot County, GA

Source: Esri, TIGER, [CLIENT], and Burns & McDonnell

Issued: 6/30/2023

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_

If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____

**If yes, are project plans/scope of work available yet?* YES _X___ NO ____

If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____
10.	Other (explain): ____________________________		

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

If your project includes...	***Then your APE would be...***
Rehabilitation, renovation, and/or demolition of a building or structure, or new construction	the building or property itself and the surrounding properties/setting with a view of the project
Road/Highway construction or improvements, streetscapes, pedestrian or bicycle facilities	the length of the project corridor and the surrounding properties/setting with a view of the project
Above ground utilities, such as siren/radio towers, water towers, pump stations, retention ponds, etc.	the area of ground disturbance and the surrounding properties/setting with a view of the project
Underground utilities	the area of ground disturbance

Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

C. Is the project located within or adjacent to a National Register of Historic Places (NRHP) listed or eligible historic property or district or a locally designated property or district?
YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
YES ____ NO _X_ DO NOT KNOW____

If yes, please identify the properties (by name or photo #).

F. Effects Information

1. Does the project involve the rehabilitation, renovation, relocation, demolition or addition to any building or structure that is 50 years old or older? YES ____ NO _X_

2. Will the project take away or change anything within the apparent or existing boundary of any of these historic properties? YES ____ NO _X_

If yes, please explain: _N/A____

3. Will the project change the view from or of any of these properties? YES ____ NO _X_
If yes, please explain: _N/A____

4. Will the project introduce any audible or atmospheric elements to the setting of any of these historic properties (such as light, noise, or vibration pollution)? YES ____ NO _X_
If yes, please explain: _N/A____

5. Will the project result in a change of ownership for any historic properties? YES ____ NO _X_
If yes, please explain: _N/A____

V. Required Materials (Submittal Checklist)

- ☐ Complete Environmental Review Form
  - Include all contact information as HPD will respond via email to the submitter.
- ☐ Map indicating:
  - Precise location of the project (USGS topographic map preferred: http://www.digital-topo-maps.com/ [1]).
  - In urban areas, please also include a city map that shows more detail
  - Boundaries of the APE as noted in section II above
  - Location of resources indicated in section IV.C through E
- ☐ Detailed project plans to supplement section I.F, including (if applicable and available):
  - Detailed scope of work
  - Site plans (before and after)
  - Project plans
  - Elevations
- ☐ High-resolution current color photographs (max 2 photos per page) illustrating:
  - The project area, the entire APE as defined in section IV, and resources indicated in section IV.C through E
  - Any adjacent properties that are within the APE, with clear views of buildings or structures, if applicable
  - If the project entails the alteration of existing historic structures, please provide ***detail*** photographs of existing conditions of sites, buildings, and interior areas/materials to be impacted
  - *****Google Street view and publicly available Tax Assessor images will not be accepted***
- ☐ Photography key (map or project plans can be used) indicating:
  - Location of all photographs by photo number
  - Direction of view for all photographs
- ☐ Any available information concerning known or suspected archaeological resources in the APE.

Email submission of project materials is available at ER@dca.ga.gov.

Documents too large to send via email may be shared only through Microsoft OneDrive file sharing.

HPD no longer accepts project materials for review via mail, with the exception of archival mitigation documentation, as applicable.

[1] *Please note, this is not a complete list of websites with topographic map information. This website is not controlled by HPD and HPD bears no responsibility for its content.*

Long, Madeline R

From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Monday, August 7, 2023 11:12 AM
To: Long, Madeline R
Subject: FW: Environmental Review Form from Burns & McDonnell for Oglethorpe Power Corp. Talbot Dual Fuel Conversion Project - Talbot County, GA.
Attachments: Talbot Dual Fuel - CR Submittal to SHPO.zip

Mike Carlock
(470) 579-3556

From: Carlock, Michael D
Sent: Thursday, July 20, 2023 9:50 AM
To: 'ER@dca.ga.gov' <ER@dca.ga.gov>
Cc: Kent, Sara S <sskent@burnsmcd.com>; Burnham, Grant M <gmburnham@burnsmcd.com>; Long, Madeline R <mrlong@burnsmcd.com>; Black, Rachel <rachel.black@dnr.ga.gov>; Stacy Rieke <Stacy.Rieke@dca.ga.gov>; Elijah Huszagh <Elijah.Huszagh@dca.ga.gov>
Subject: Environmental Review Form from Burns & McDonnell for Oglethorpe Power Corp. Talbot Dual Fuel Conversion Project - Talbot County, GA.

Hello,

Please find attached an environmental review form and attachments for the above project for your review. As follow-up to previous informal emails with SHPO and OSA, Burns & McDonnell is seeking official SHPO concurrence regarding the adequacy of previous survey coverage for the Talbot Dual Fuel Conversion Project in Talbot County, Georgia.

Thank you,

Michael D. Carlock \ Burns & McDonnell
Senior Cultural Resources Specialist
O – (470) 579-3556
mdcarlock@burnsmcd.com \ burnsmcd.com
4004 Summit Blvd., Ste 1200 \ Atlanta, GA 30319

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Environmental Review Form

At a minimum, the Historic Preservation Division (HPD) requires the following information in order to review projects in accordance with applicable federal or state laws. Please note that the responsibility for preparing documentation, including items listed below, rests with the federal or state agency or its designated applicant. *HPD's ability to complete a timely project review largely depends on the quality and detail of the material submitted. If insufficient information is provided, HPD may need to request additional materials, which will prolong the review process. For complex projects, some applicants may find it advantageous to hire a preservation professional with expertise in history, architectural history, and/or archaeology, who would have access to the Georgia Archaeological Site Files and an understanding of HPD's publicly available files.*

THERE IS A 30-DAY REVIEW PERIOD FROM THE DATE HPD RECEIVES THE SUBMITTAL.
SHOULD ADDITIONAL INFORMATION BE REQUESTED, PLEASE NOTE THE 30-DAY PERIOD RESTARTS.

I. General Information

A. Project Name: _Talbot County Energy Facility Dual Fuel Conversion Project

Project Address: _9125 Cartledge Road

City: _Box Springs County: _Talbot County, Georgia

B. Federal Agency Involved: _USDA Rural Development (RD) Rural Utilities Service (RUS)

State Agency Involved *(if applicable)*: _N/A

C. Agency's Involvement *(check all that are applicable)***:**

X Funding (grant, loan, etc.)
☐ License/Permit
☐ Direct/Agency is performing the action
☐ Unknown
☐ Other, please explain: ______________________________

D. Type of Review Requested:

X Section 106 of the National Historic Preservation Act (Federal agency involvement)
☐ Section 110 of the National Historic Preservation Act (Federally owned properties)
☐ Georgia Environmental Policy Act (GEPA; State agency involvement)
☐ State Agency Historic Property Stewardship Program/State Stewardship (State owned properties)
☐ Unknown

E. Contact Information: ☐ **Applicant** X **Consultant**

Name/Title/Company: _Michael D. Carlock, Senior Cultural Resources Specialist, Burns & McDonnell

Address: _4004 Summit Boulevard, Suite 1200

City/State/Zip: _Atlanta, GA 30319

Phone: _470-527-3556 Email: _mdcarlock@burnsmcd.com

Agency Contact Info *(either State or Federal, according to review type)*:

Name/Title/Agency: _Gregory Korosec, Archaeologist, Rural Utilities Service, Rural Development, USDA

Address: _1400 Independence Avenue, S.W.

City/State/Zip: _Washington, D.C. 20250

Phone: _202-720-2662 Email: _Gregory.Korosec@usda.gov

II. Project Information

A. Project Type:

- ☐ Road/Highway Construction or Improvements
- ☐ Demolition
- ☐ Rehabilitation
- ☐ Addition to Existing Building/Structure
- ☐ New Construction
- ☐ Relicensing
- X Utilities/Infrastructure
- ☐ Unknown
- ☐ Other: ________________________

B. Project Description and Plans This should include a *detailed* **scope of work**, including *any* actions to be taken in relation to the project, such as all aspects of new construction, replacement/repair, demolition, ground disturbance, and all ancillary work (temporary roads, etc.), as applicable. Attach additional pages if necessary. If a detailed scope of work is not available yet, please explain and include all preliminary information:

Oglethorpe Power Corporation's (Oglethorpe) proposed Talbot Energy Facility Dual Fuels Project (Project) involves upgrading four of the Talbot Energy Facility's (Facility) natural gas-fired simple-cycle combustion turbines (CTs) to dual fuel CTs that utilize both natural gas and No. 2 diesel fuel oil. This dual fuel conversion will increase the resiliency and reliability of the facility's electrical output by allowing for a back-up fuel source during times of heavy loads when natural gas supply is curtailed or cut off. The proposed infrastructure required for this Project includes two diesel fuel oil storage tanks and two demineralized water storage tanks, along with associated mechanical and software upgrades. With the exception of approximately 0.85 acres, the entire Project will occur within the existing Facility footprint.
Please review the attached Project Description for the Project's detailed scope of work.

C. Land Disturbing Activity This should include a detailed description of all horizontal and vertical ground disturbance, such as haul roads, cut or fill areas, excavations, landscaping activities, ditching, utility burial, grading, water tower construction, etc., as applicable:

All ground disturbance would occur within the existing footprint of the Talbot Energy Facility (Facility), with the exception of approximately 0.85 acres on the southeast corner of the Facility that would be cleared and graded to install secondary containment infrastructure similar to that just to the north, including modified slope and riprap (see attached).

D. Has this identical project or a related project been previously submitted to HPD for review? YES ____ NO _X_
If yes, please enclose a copy of HPD's previous response

E. Is this project also being reviewed under a tax incentive program administered through HPD? YES ____ NO _X_

F. Is this review request in order to satisfy an application requirement, such as for a grant? YES _X___ NO ____
****If yes, are project plans/scope of work available yet?*** YES _X___ NO ____
****If yes, please enclose a copy of the project plans/scope of work as outlined in II.B and II.C above***

III. Site Information

A. In the past this property has been used for:

1.	Farming	YES ____	NO ____
2.	Pasture	YES ____	NO ____
3.	Mining	YES ____	NO ____
4.	Timbering	YES _X_	NO ____
5.	Road construction	YES ____	NO ____
6.	Housing	YES ____	NO ____
7.	Landfill	YES ____	NO ____
8.	Commercial	YES ____	NO ____
9.	Industrial	YES ____	NO ____

10. Other (explain): ____________________________

B. Describe what currently exists on the property today and give approximate construction dates for existing buildings along with any known history (i.e. buildings, parking lot, outbuildings, woods, grass, garden, etc.): _The Talbot Energy Facility is located on the existing parcel. It was built by Oglethorpe Power Corporation in 2002. ____

IV. Cultural Resources

Background research for previously identified properties within the project area may be undertaken at HPD, including National Register of Historic Places files, county and city surveys, and identified sites files. Additionally, research at the Georgia Archaeological Site Files (GASF) in Athens may be undertaken by a qualified archaeologist or site file staff. To make a research appointment or find contact information for GASF, please visit our website. **Please note that as part of the review process, HPD may request an archaeological survey or resource identification.**

A. To your knowledge, has a cultural resources assessment or a historic resources survey been conducted in the project area? YES_X_ NO______ DO NOT KNOW______(see: http://www. https://georgiashpo.org/surveys)

If yes, provide the title, author, and date of the report:

_Joseph, J.W. 2000 A Cultural Resources Survey of 190 Acre Tract of Land, Talbot County, Georgia

B. Area of Potential Effect (APE)

The APE is the geographic area or areas within which a project may cause changes (or effects). These changes can be direct (physical) or indirect (visual, noise, vibrations) effects. The APE varies with the project type and should factor in topography, vegetation, existing development, physical siting of the project, and existing/planned development. For example:

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Based on this information, **identify the APE for your project, similar to above AND describe what exists within it.** Please provide approximate construction dates for existing buildings within the APE (i.e., is it modern or historic residential or commercial development, undeveloped, etc.): _The APE for this project includes the footprint of the existing modern facility and surrounding properties with a view of the project. The existing facility is a collection of modern energy generating structures that was built in 2002. The entire APE was the subject of an archaeological survey in 2000, by New South Associates.

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YES ____ NO _X_ DO NOT KNOW ____

If yes, please provide names: __N/A____

D. Within the project APE as identified in IV.B, are there any other buildings or structures that are 50 years old or older?
YES ____ NO _X_ DO NOT KNOW ____

If yes, provide current photographs of each building or structure and key the photos to a site map.

E. Are any of the buildings or structures identified in IV.D listed or eligible for listing in the NRHP?
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   ***If yes, please explain:** _N/A____

V. Required Materials (Submittal Checklist)

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    - In urban areas, please also include a city map that shows more detail
    - Boundaries of the APE as noted in section II above
    - Location of resources indicated in section IV.C through E
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    - Site plans (before and after)
    - Project plans
    - Elevations
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AGENCY RESPONSES

USDA

United States Department of Agriculture

July 7, 2023

Sara Kent, Project Manager
Burns & McDonnell
4004 Summit Boulevard NE, Suite 120
Atlanta, GA 30319

Re: Executive Order 12372 Request for Talbot Energy Facility, Talbot County.

Dear Ms. Kent:

This letter replies to your request for information on the possible impacts the proposed new infrastructure for the facility may have on land use, conservation, water quality and other general environmental concerns that may be of interest to our agency. The following outlines our concerns with the proposed project with regards to farmland protection, and Natural Resources Conservation Service (NRCS) watershed dams and project easements.

Farmland Protection

The Farmland Protection Policy Act (FPPA) is intended to minimize the impact federal programs have on the unnecessary and irreversible conversion of farmland to nonagricultural uses. Projects are subject to FPPA requirements if they may irreversibly convert farmland (directly or indirectly) to nonagricultural use and are completed by a federal agency or with assistance from a federal agency. For FPPA purposes, farmland includes areas located within soil map units rated as prime farmland, unique farmland, or land of statewide or local importance not currently in urban/built up land use. Farmland subject to FPPA requirements does not have to be currently used for cropland. It can be forest land, pastureland, cropland, or other land uses, but not water or urban built-up land. It should be noted that the FPPA does not authorize the Federal Government to regulate the use of private or nonfederal land or, in any way, affect the property rights of owners.

NRCS uses a Land Evaluation and Site Assessment (LESA) system to establish a farmland conversion impact rating score on proposed sites of federally funded and assisted projects. This score is used as an indicator for the project sponsor to consider alternative sites if the potential adverse impacts on the farmland exceed the recommended allowable level. It is our understanding that the proposed project involves federal funds or assistance, and thus could be subject to this assessment. **However, this project does not convert farmland and is thus exempt from this assessment. You need take no further action for FPPA purposes.**

NRCS Watershed Dams

More than 50 years ago, the U.S. Department of Agriculture was authorized by Congress to help local communities with flood control and watershed protection through the Watershed Program (PL-534 Flood Control Act of 1944 and PL-566 Watershed Protection and Flood Prevention Act). As a result, local communities, with NRCS assistance, have constructed over 11,000 dams in 47 states since 1948. These dams were originally constructed for protection of

Natural Resources Conservation Service
Georgia State Office
355 East Hancock Avenue - Athens, GA - 30601-2775
Voice: 706-546-2272 Fax: 855-417-8490

farmlands from flooding impacts. In 2000, PL-566 was amended to provide NRCS authorization to assist communities with rehabilitation of their aging dams. The legislation authorizes NRCS to work with local communities and watershed project sponsors to address public health and safety concerns and potential environmental impacts of aging dams.

We have reviewed our records and have determined that there are no such structures downstream of the proposed project that could be affected by these activities.

NRCS Easements

NRCS easements relate to our Wetland Reserve Program and the Farm and Ranchland Protection Program. **We have reviewed our records and have determined that there are no such easements downstream or in the near vicinity of the proposed project that could be affected by these activities.**

NRCS appreciates this opportunity to comment. If you have questions or need any additional information, please contact me at (706) 654-2056 or nelson.velazquezgotay@usda.gov.

Sincerely,

NELSON A. VELÁZQUEZ GOTAY
SOIL SCIENTIST

cc: Steve Blackston, Acting Assistant State Conservationist (FO), NRCS, Griffin, GA
Kendric Holder, District Conservationist, NRCS, Buena Vista, GA
Michael Henderson, Resource Soil Scientist, NRCS, Griffin, GA

Long, Madeline R

From: Long, Madeline R <mrlong@burnsmcd.com>
Sent: Wednesday, August 16, 2023 12:54 PM
To: GAES Assistance, FW4; Sandy_Abbott@fws.gov
Cc: Kent, Sara S
Subject: Re: [EXTERNAL] 2023-0110820 Talbot Co.

Hi Sandy,

Thank you for letting us know.

Have a great rest of your week!

Best,
Madeline

Madeline Long \ Burns & McDonnell
Assistant Environmental Scientist
o +1 470-548-7631
mrlong@burnsmcd.com \ burnsmcd.com
4004 Summit Blvd. | Suite 1200 | Atlanta, GA 30319

From: GAES Assistance, FW4 <gaes_assistance@fws.gov>
Sent: Wednesday, August 16, 2023 12:22 PM
To: Long, Madeline R <mrlong@burnsmcd.com>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: Re: [EXTERNAL] 2023-0110820 Talbot Co.

Madeline,

Based on the information provided, the proposed action (Oglethorpe's Dual Fuel Conversion Project (Project) at the Talbot Energy Facility) is not expected to significantly impact fish and wildlife resources under the jurisdiction of the U.S. Fish and Wildlife Service. If you have any questions or need any additional information, please let me know.

Thank you,
Sandy Abbott
Sandy_Abbott@fws.gov

Georgia Ecological Services
U.S. Fish and Wildlife Service
GAES_Assistance@FWS.gov
www.fws.gov/office/georgia-ecological-services/
Check out our new project review and conservation tools pages!
ESA 50th Anniversary - More Important than Ever

From: Long, Madeline R <mrlong@burnsmcd.com>
Sent: Monday, July 31, 2023 11:54 AM
To: GAES Assistance, FW4 <gaes_assistance@fws.gov>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: [EXTERNAL] 2023-0110820 Talbot Co.

Good morning,

I'm reaching out in regard to the automated reply that was sent from U.S. Fish and Wildlife Serivces's Georgia Ecological Serivces Field Office in response to the scoping letter sent on behalf of our client, Oglethorpe Power Company (Oglethorpe).

Per the instructions attached to the automated response, I have completed, and attached, the IPaC Report for Oglethorpe's Dual Fuel Conversion Project (Project) at the Talbot Energy Facility. The Project site is located at 9125 Cartledge Road in Box Springs, Georgia, at the following coordinates: 32.588843°N, 84.692115°W.

I completed the *Clearance to Proceed with Federally-Insured Loan and Grant Project Requests* determination key (responses and results attached). The key concluded that the Project was "not applicable for species or critical habitats covered by the key."

I've also attached a Project description that includes the requested effects determination and conservation measures.
In summary, no impacts to natural resources are anticipated as a result of this Project; thus, no mitigation measures have been proposed.

Please reach out if you have any questions.

Thank you for your time and consideration, and I look forward to hearing from you.

Best,
Madeline

Madeline Long \ Burns & McDonnell
Assistant Environmental Scientist
o +1 470-548-7631
mrlong@burnsmcd.com \ burnsmcd.com
4004 Summit Blvd. | Suite 1200 | Atlanta, GA 30319

Long, Madeline R

From: Kent, Sara S <sskent@burnsmcd.com>
Sent: Wednesday, August 2, 2023 4:30 PM
To: Smith, Adam
Cc: Duff, Eric; Long, Madeline R
Subject: RE: Talbot Energy Facility Dual Fuel Conversion Project
Attachments: Talbot Energy Facility Dual Fuel Conversion Project.pdf

Mr. Smith,

Thank you for the response, and please let us know if you have any questions. Thanks!

Sara Kent \ Burns & McDonnell
Section Manager, Environmental Services
O 470-508-9904 \ **M** 770-363-1453
sskent@burnsmcd.com \ burnsmcd.com
4004 Summit Boulevard \ Suite 1200 \ Atlanta, GA 30319

From: Smith, Adam <adsmith@dot.ga.gov>
Sent: Tuesday, August 1, 2023 10:35 AM
To: Kent, Sara S <sskent@burnsmcd.com>
Cc: Duff, Eric <eduff@dot.ga.gov>
Subject: FW: Talbot Energy Facility Dual Fuel Conversion Project

Ms. Kent,

I am in receipt of the attached letter. I do not see where our District Office would need to have any input. I am copying our Environmental Office to see if they will be required to participate in any way.

Thanks,

Adam G. Smith, P.E.
District 3 Preconstruction Engineer
GDOT Georgia Department of Transportation
Email: adsmith@dot.ga.gov
115 Transportation Blvd.
Thomaston, GA 30286
Cell Phone: 706-621-9704
Office Phone: 706-646-7623
Fax: 706-646-7617

From: Smith, Greg <grsmith@dot.ga.gov>
Sent: Monday, July 31, 2023 8:47 AM
To: Smith, Adam <adsmith@dot.ga.gov>
Subject: Talbot Energy Facility Dual Fuel Conversion Project

Adam,

Attached is the document discussed on the phone. Thanks again.

Thanks,
Greggory W. Smith
District Utilities Manager

District 3 Utilities Office
115 Transportation Blvd., Thomaston, GA, 30286
706.646.7605 office / 706.741.7308 cell

Long, Madeline R

From: Kent, Sara S <sskent@burnsmcd.com>
Sent: Wednesday, August 9, 2023 2:54 PM
To: Duff, Eric
Cc: Long, Madeline R
Subject: RE: Talbot Energy Facility Dual Fuel Conversion Project

Received, thanks Eric!

Sara Kent \ Burns & McDonnell
Section Manager, Environmental Services
O 470-508-9904 \ **M** 770-363-1453
sskent@burnsmcd.com \ burnsmcd.com
4004 Summit Boulevard \ Suite 1200 \ Atlanta, GA 30319

From: Duff, Eric <eduff@dot.ga.gov>
Sent: Wednesday, August 9, 2023 2:13 PM
To: Kent, Sara S <sskent@burnsmcd.com>
Subject: FW: Talbot Energy Facility Dual Fuel Conversion Project

See below.

From: Phillips, Amber <aphillips@dot.ga.gov>
Sent: Wednesday, August 9, 2023 1:11 PM
To: Duff, Eric <eduff@dot.ga.gov>
Subject: RE: Talbot Energy Facility Dual Fuel Conversion Project

No comments from us.

Amber L. Phillips
Assistant Environmental Administrator

GDOT Georgia Department of Transportation

Office of Environmental Services
One GA Center
600 West Peachtree Street
Floor 16
Atlanta, GA 30308
Phone: 404-631-1117
Cell: 470-755-3456

From: Duff, Eric <eduff@dot.ga.gov>
Sent: Thursday, August 3, 2023 2:17 PM

To: Phillips, Amber <aphillips@dot.ga.gov>
Subject: FW: Talbot Energy Facility Dual Fuel Conversion Project

Do we have any comments on this proposed development?

From: Kent, Sara S <sskent@burnsmcd.com>
Sent: Wednesday, August 2, 2023 4:30 PM
To: Smith, Adam <adsmith@dot.ga.gov>
Cc: Duff, Eric <eduff@dot.ga.gov>; Long, Madeline R <mrlong@burnsmcd.com>
Subject: RE: Talbot Energy Facility Dual Fuel Conversion Project

Mr. Smith,

Thank you for the response, and please let us know if you have any questions. Thanks!

Sara Kent \ Burns & McDonnell
Section Manager, Environmental Services
O 470-508-9904 \ M 770-363-1453
sskent@burnsmcd.com \ burnsmcd.com
4004 Summit Boulevard \ Suite 1200 \ Atlanta, GA 30319

From: Smith, Adam <adsmith@dot.ga.gov>
Sent: Tuesday, August 1, 2023 10:35 AM
To: Kent, Sara S <sskent@burnsmcd.com>
Cc: Duff, Eric <eduff@dot.ga.gov>
Subject: FW: Talbot Energy Facility Dual Fuel Conversion Project

Ms. Kent,

I am in receipt of the attached letter. I do not see where our District Office would need to have any input. I am copying our Environmental Office to see if they will be required to participate in any way.

Thanks,

Adam G. Smith, P.E.
District 3 Preconstruction Engineer
GDOT Georgia Department of Transportation
Email: adsmith@dot.ga.gov
115 Transportation Blvd.
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Cell Phone: 706-621-9704
Office Phone: 706-646-7623
Fax: 706-646-7617

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District 3 Utilities Office
115 Transportation Blvd., Thomaston, GA, 30286
706.646.7605 office / 706.741.7308 cell

Long, Madeline R

From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Wednesday, July 12, 2023 11:32 AM
To: Kent, Sara S
Cc: Burnham, Grant M; Long, Madeline R
Subject: FW: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hi All,

Please see below. Both Georgia Office of the State Archaeologist and SHPO concur that no additional archaeological survey is required for this project. Grant and Madeline, I guess I won't be seeing you tomorrow morning after all. Sara, I was literally on my way to pick up my rental vehicle when we got final agreement from SHPO. I didn't pick it up and will cancel it now. I will write a letter today stating that SHPO/OSA waived the need for survey and get it to you asap.

Thanks!

Mike Carlock
(470) 579-3556

From: Elijah Huszagh <Elijah.Huszagh@dca.ga.gov>
Sent: Wednesday, July 12, 2023 11:25 AM
To: Carlock, Michael D <mdcarlock@burnsmcd.com>
Cc: Stacy Rieke <Stacy.Rieke@dca.ga.gov>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hi Michael,

After reviewing the materials, I find that the previous survey methodology meets the GCPA *Standards and Guidelines for Archaeological Investigations.* The previous survey coverage from New South & Associates Phase I investigation in 2000 should be adequate in identifying any cultural resources that may be present within the project area, and thus, an additional phase I survey within the same area is not necessary.

Best,
Eli Huszagh
Elijah Huszagh
Compliance Review Archaeologist
Georgia Department of Community Affairs
Direct 404-486-6440
Elijah.Huszagh@dca.ga.gov

From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Wednesday, July 12, 2023 10:59 AM
To: Elijah Huszagh <Elijah.Huszagh@dca.ga.gov>
Cc: Stacy Rieke <Stacy.Rieke@dca.ga.gov>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hello Eli,

I really appreciate your quick response earlier. Please find attached the maps and documentation for this project.

Thank you,

Mike Carlock
(470) 579-3556

From: Elijah Huszagh <Elijah.Huszagh@dca.ga.gov>
Sent: Wednesday, July 12, 2023 10:34 AM
To: Carlock, Michael D <mdcarlock@burnsmcd.com>
Cc: Stacy Rieke <Stacy.Rieke@dca.ga.gov>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hello Michael,

I am one of the compliance review archaeologists at the Georgia State Historic Preservation Office, and I would be happy to help answer your question. Would you please send over the documents mentioned in the email chain to me, as I am not seeing them attached.

Thanks,
Eli Huszagh

Elijah Huszagh
Compliance Review Archaeolog
Georgia Department of Commu

Direct 404-486-6440
Elijah.Huszagh@dca.ga.gov

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From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Wednesday, July 12, 2023 10:11 AM
To: Stacy Rieke <Stacy.Rieke@dca.ga.gov>
Subject: Fwd: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hello Stacy,

My name is Michael Carlock, and I'm a Senior Archaeologist for Burns & McDonnell in Atlanta. I have a question regarding previous survey coverage for a current project I am working on in Talbot County. Please see the below emails for project description, survey information, and the opinion of the OSA. Please let me know if you agree with Ms. Black's opinion.

Thank you so much,

Michael Carlock

From: Black, Rachel <Rachel.Black@dnr.ga.gov>
Sent: Wednesday, July 12, 2023 9:56 AM
To: Carlock, Michael D <mdcarlock@burnsmcd.com>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hi Mike,

Get in touch with Stacy Rieke (stacy.rieke@dca.ga.gov). She is the Environmental Review Program manager.

Best,
Rachel

Rachel Black
State Archaeologist
Office of the State Archaeologist
State Parks and Historic Sites Division
O: (770) 389-7862
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From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Wednesday, July 12, 2023 9:52 AM
To: Black, Rachel <Rachel.Black@dnr.ga.gov>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: Re: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hi Rachel,

Thanks for getting back to me. I apologize, I didn't realize SHPO and OSA were separate in that way. If you don't mind, who might I forward this to at SHPO? (I actually have the survey planned for tomorrow, but if SHPO agreed, that would be great!)

Please let me know.

Thank you,

Michael Carlock

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From: Black, Rachel <Rachel.Black@dnr.ga.gov>
Sent: Wednesday, July 12, 2023 9:30:19 AM
To: Carlock, Michael D <mdcarlock@burnsmcd.com>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Good morning Mike,

My apologies for the delay in getting back with you.

Even though a project-wide shovel test map was not included in Joseph 2000, the text indicates the whole project area was shovel tested per methods stipulated in the *Georgia Standards and Guidelines for Archaeological Investigations* (see attached for complete report). These Phase I shovel test standards remain the same in the current version of the *Standards*. As well, the 2000 report notes deflated soils, erosional activity, and subsoil seen at the surface throughout the project area.

Based on these findings, it is my opinion that the archaeological investigations conducted in 2000 were adequate for locating archaeological resources in the project area and that additional investigations within your newly identified 0.75 acre APE are not warranted.

However, this is the opinion or the Office of the State Archaeologist which is separate from the State Historic Preservation Office (SHPO). Should this project be subject to Section 106 review, the SHPO's office may provide a different recommendation.

Best,
Rachel

Rachel Black
State Archaeologist
Office of the State Archaeologist
State Parks and Historic Sites Division
O: (770) 389-7862
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From: Carlock, Michael D <mdcarlock@burnsmcd.com>
Sent: Monday, July 3, 2023 1:29 PM
To: Black, Rachel <Rachel.Black@dnr.ga.gov>
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: RE: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hi Rachel,

I am just checking in to see if you received my email on the 23rd. Please let me know.

Thank you,

Mike Carlock
(470) 579-3556

From: Carlock, Michael D
Sent: Friday, June 23, 2023 9:38 AM
To: rachel.black@dnr.ga.gov
Cc: Kent, Sara S <sskent@burnsmcd.com>
Subject: Previous Survey Coverage of a Proposed Energy Project in Talbot County, GA

Hello Rachel,

My name is Mike Carlock, and I am a Senior Archaeologist at Burns & McDonnell Engineering. I am currently doing background research for a project in Talbot County, GA. I have a question regarding previous survey coverage and would like your opinion regarding the need for new archaeological survey. Please find attached location and cultural maps of the project, along with the site forms and previous survey report in question.

The project consists of equipment updates and conversions to other fuel types and was originally going to take place entirely within the existing graded facility. However, the company has since realized that there may need to be additional clearing of trees and riprap placement along a new fence line.

The additional required APE measures less than an acre (approximately 0.75 ac), the entire proposed project area (graded facility and additional APE) has been previously surveyed (J.W. Joseph 2000) and all three known sites near the facility have been recommended ineligible for the NRHP.

Please let me know if the previous survey provides adequate coverage for this proposed project. I would greatly appreciate any guidance you can provide.

Thank you,

Michael D. Carlock \ Burns & McDonnell
Senior Cultural Resources Specialist
O – (470) 579-3556
mdcarlock@burnsmcd.com \ burnsmcd.com
4004 Summit Blvd., Ste 1200 \ Atlanta, GA 30319

Brian P. Kemp
Governor

Georgia® Department of Community Affairs
HISTORIC PRESERVATION DIVISION

Christopher Nunn
Commissioner

August 10, 2023

Michael Carlock
Senior Cultural Resources Specialist
Burns & McDonnell
4004 Summit Boulevard, Suite 1200
Atlanta, Georgia 30319

RE: Upgrade Talbot Energy Facility, 9125 Cartledge Road, Box Springs
Talbot County, Georgia
HP-230720-003

Dear Mr. Carlock,

The Historic Preservation Division (HPD) has received the information submitted concerning the above referenced undertaking, including the report entitled *A Cultural Resources Survey of a 190 Acre Tract of Land, Talbot County, Georgia* prepared by New South Associates and dated September 13, 2000. Our comments are offered to assist the U.S. Department of Agriculture (USDA) Rural Utilities Services (RUS) and its applicants in complying with the provisions of Section 106 of the National Historic Preservation Act of 1966, as amended (NHPA).

The subject project consists of the upgrading four (4) turbines to utilize both natural gas and diesel fuel oil, installing two (2) diesel storage tanks and 2 water storage tanks, and making associated mechanical and software upgrades to the Talbot Energy Power Plant on Talbot County parcels 005 00705 IND/circa (ca.) 2004 and 005 00701 IND/vacant located at 9125 Cartledge Road in Box Springs. Based on the information provided, HPD concurs that archaeological site 9TA112 is not eligible for listing in the National Register of Historic Places (NRHP) due to a lack of significance and/or integrity. Therefore, HPD concurs that no historic properties that are listed or eligible for listing in the National Register of Historic Places will be affected by this undertaking, as defined in 36 CFR Part 800.4(d)(1).

This letter evidences consultation with our office for compliance with Section 106 of the NHPA. Please note that historic and/or archaeological resources may be located within the project's area of potential effect (APE). However, at this time it appears that they will not be impacted by the above-referenced project, due to the scope and location of work. It is important to remember that any changes to this project as it is currently proposed may require additional consultation. HPD encourages federal agencies and project applicants to discuss such changes with our office to ensure that potential effects to historic resources are adequately considered in project planning.

Please refer to project number **HP-230720-003** in any future correspondence regarding this project. If we may be of further assistance, please contact Michelle Bard, Environmental Review Historian, at Michelle.Bard@dca.ga.gov or (770) 212-4888.

Sincerely,

Stacy Rieke

Stacy Rieke, MHP
Program Manager
Environmental Review & Preservation Planning

SMR/mlb

cc: Alison Slocum, River Valley Regional Commission
Rebecca White, DCA Regional Services, Region 8