Florida Electrical Power Plant Siting Act

Site Certification Application

Volume 3 of 3

Treasure Coast Energy Center

Submitted by:
Florida Municipal Power Agency
April 2005

Florida Municipal Power Agency
Community Power. Statewide Strength.

Treasure Coast
ENERGY CENTER

Adams, Patty

From: Adams, Patty
Sent: Thursday, April 21, 2005 10:35 AM
To: 'worley.gregg@epa.gov'
Cc: Graziani, Darrel; Mulkey, Cindy; Linero, Alvaro
Subject: PSD-FL-353, 1110121-001-AC, Treasure Coast Energy Center

The Bureau of Air Regulation is transmitting to you by this email an electronic version of a PSD application submitted by the Florida Municipal Power Agency (FMPA) for construction of the Treasure Coast Energy Center in Fort Pierce, St. Lucie County, Florida.

Your comments may be forwarded to Al Linero at the Bureau of Air Regulation or faxed to 850-921-9533. If you have any questions, please contact Cindy Mulkey, review engineer, at 850-921-8968.

Sincerely,
Patty Adams
850-921-9505

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1.0 Introduction

The Florida Municipal Power Agency (FMPA) proposes to install a 1x1 F-Class Combined Cycle Unit and associated support facilities (Project) at the new Treasure Coast Energy Center (hereinafter referred to as the Energy Center), near Fort Pierce, St. Lucie County, Florida. The Energy Center will include a 1x1 combined cycle unit (Unit 1) which will include a combustion turbine generator (CTG), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG), operating at a nominal rating of 300 MW. New major support facilities include an approximately 990,000 gallon fuel oil storage tank, a natural gas fired auxiliary boiler, a diesel engine driven fire pump and associated 500 gallon fuel oil storage tank, a safe shutdown generator and a mechanical draft cooling tower.

This report is a technical support document for the Prevention of Significant Deterioration Air Permit Application. The following sections contain a project characterization, best available control technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project, including a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability and a regulatory review.

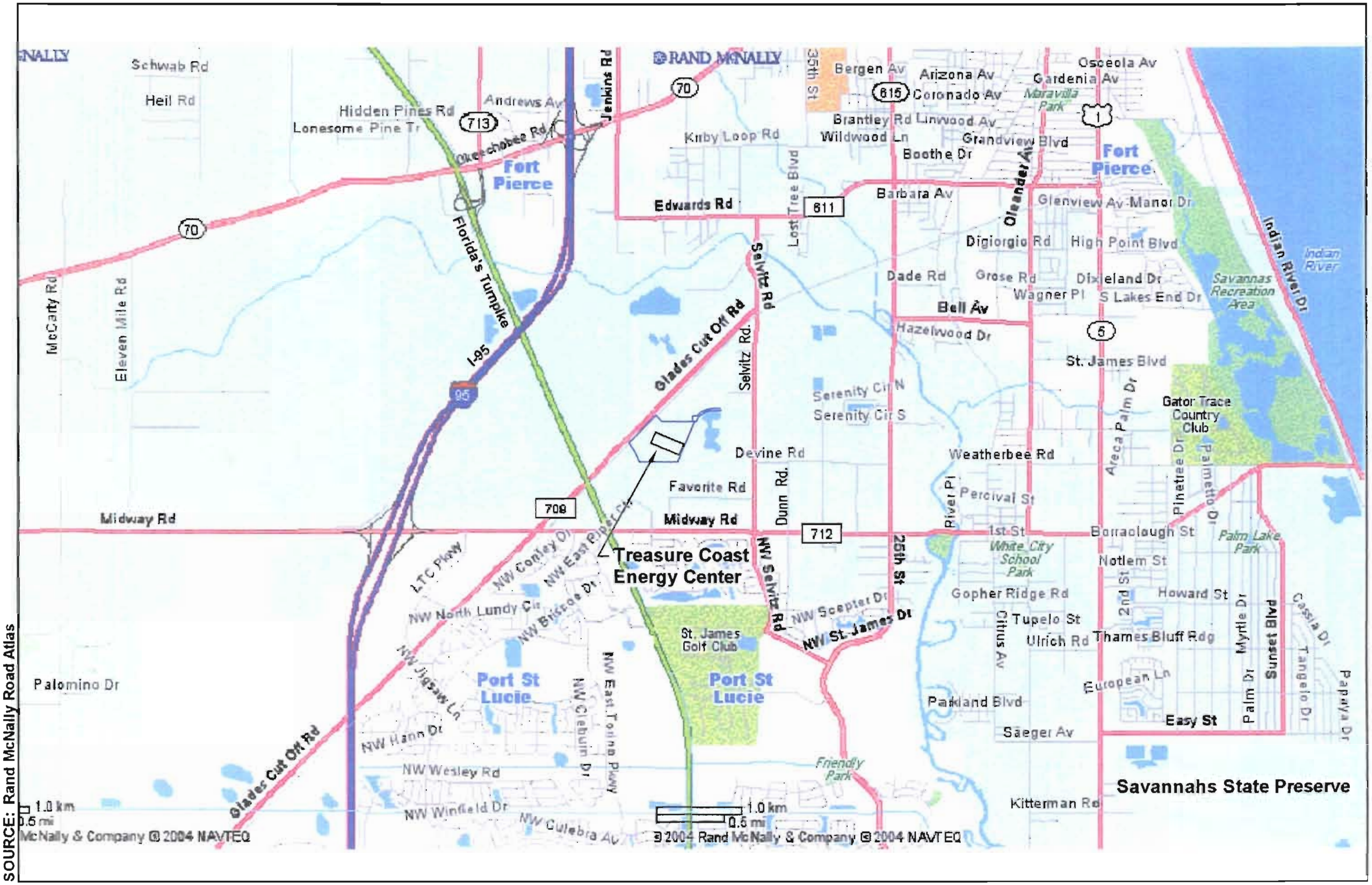
2.1 Project Location

The Project is located in St. Lucie County, Southwest of the City of Fort Pierce. Figure 2-1 shows the general location of the Project. The approximate UTM coordinates of the site are 561,516.1 m East and 3,028,996.3 m North (Zone 17). The nearest Federal Prevention of Significant Deterioration (PSD) Class I Area is the Everglades National Park (ENP), located approximately 180 km Southwest of the Project site. The Chassahowitzka class 1 area is approximately 260 km Northwest of the Project site. The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

The Project installation will be a 1x1 F-Class Combined Cycle Unit (Unit 1) which will include a combustion turbine generator (CTG), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG). Unit 1 will have a nominal rating of 300 MW. New major support facilities include an approximately 990,000 gallon fuel oil storage tank, a natural gas fired auxiliary boiler, a diesel engine driven fire pump with an associated 500 gallon fuel oil storage tank, a safe shutdown generator with an associated 1,000 gallon fuel oil storage tank, and a mechanical draft cooling tower.

Unit 1 will be dual fueled with natural gas as the primary fuel and ultra-low sulfur (ULS) fuel oil (0.0015 percent sulfur) as an alternate fuel. The CTG will have an evaporative cooler to increase warm weather power generation by increasing the CTG inlet air density. Power augmentation systems for the CTG are not included. The CTG will be designed to operate in a pseudo simple cycle mode where the steam from the HRSG bypasses the steam turbine and is dumped to the condenser. Air emissions when operating in this pseudo-simple cycle mode are expected to be no different then the air emissions when operating in typical combined cycle mode operation, as the combustion gases will still pass through the HRSG and the SCR will still be used for control of NO_X emissions.



SOURCE: Rand McNally Road Atlas

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1 1/2 0 1
SCALE IN MILES

TREASURE COAST ENERGY CENTER

PROPOSED PROJECT LOCATION

FIGURE 2-1

2.2.1 Combustion Turbine Generator (CTG)

The PSD application is based on a General Electric PG7241 FA enhanced combustion turbine generator with modulating inlet guide vanes installed outdoors. The combustion turbine generator unit will include the following major features:

- Dual fuel firing system using natural gas or ULS fuel oil.
- Dry low NO_x combustion system for natural gas firing.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Self cleaning inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Water injection system for NO_x reduction when firing fuel oil.
- Fire detection/carbon dioxide fire protection systems.
- Mark VI control system.
- Off-line/on-line water wash system.
- Package Electrical and Electronics Control Compartment.

2.2.2 Heat Recovery Steam Generator (HRSG)

The HRSG will convert waste heat from the CTG exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three pressure, reheat unit with supplemental duct firing by natural gas only to maximize unit output. Selective catalytic reduction (SCR) for NO_x control is included. The HRSG will discharge to a metal exhaust stack approximately 170 feet tall. A stack damper will be included to minimize heat loss during unit shutdowns.

2.2.3 Steam Turbine Generator (STG)

The STG is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one high pressure section with a nominal 1,800 psig throttle pressure, one intermediate pressure section, and one low pressure section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring and control systems are included. A surface condenser is included for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. A single synchronous generator is included which will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment, supervisory, monitoring, and control systems, and static excitation system are included.

A 5,000 pounds per hour natural gas fired auxiliary boiler will be included to provide steam for the STG steam seal system during startups.

2.2.4 Cooling Tower

A multiple cell, mechanical draft, counterflow cooling tower will be used for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin which will include a pump intake structure housing the two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. Circulating water chemical feed system will be included. Makeup water to the cooling tower is expected to be from treated sewage plant effluent (reclaimed water). Provisions will be included to utilize municipal water and groundwater as emergency sources of cooling tower makeup. The cooling tower will be equipped with drift eliminators with a design drift rate of 0.0005 percent of the circulating water flow rate.

2.2.5 Mode of Operation

Unit 1 is designed for unlimited operation on natural gas and up to 500 hours per year of operation with ULS fuel oil, including an unlimited number of starts annually. A maximum of approximately 300 starts are expected annually, with an expected breakdown of 50 cold starts, 200 warm starts and 50 hot starts.

2.2.6 Fuel

The fuel for Unit 1 will be natural gas and ULS (0.0015 percent sulfur) fuel oil. Natural gas will be delivered to the site by existing and new pipelines from Florida Gas Transmission (FGT). Fuel oil delivery will be by truck. Fuel oil storage of slightly less than one million gallons will be provided to allow full load operation for approximately 3 days. A truck unloading and transfer station will be installed. The fuel oil tank will be installed within a dike area to provide containment. A foam fire suppression system will be installed on the fuel oil tank. This application is for unlimited operation on natural gas and up to 500 hours per year of operation with ULS fuel oil.

2.2.7 Air Quality Control

The Project is a prevention of significant deterioration (PSD) major source. Based on the BACT analysis, emission control for NO_x will be by the use of combustion turbine dry low NO_x burners and SCR when firing natural gas or water injection and SCR when firing ULS fuel oil. Control of other pollutants will be by good combustion control and use of natural gas and ULS fuel oil.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- One General Electric CCCT/HRSG with supplemental duct firing (Unit 1).
- One natural gas fired auxiliary boiler.
- One diesel engine driven fire pump with associated 500 gallon fuel oil storage tank.
- One safe shutdown generator with associated 1,000 gallon fuel oil storage tank.
- One approximately 990,000 gallon fuel oil storage tank.
- One mechanical draft cooling tower.

The emission calculations for each of these emission units are shown in Appendix A. The following sections briefly describe the basis for the emission calculations.

2.3.1 Unit 1 Emissions

Performance data for Unit 1 at loads of 40, 50, 75, and 100 percent, natural gas or distillate fuel oil firing, and ambient air temperatures of 26° F, 59° F, 73° F, and 100° F are provided in Appendix A.

Ambient temperature data were selected based on meteorological data from St. Lucie County, Florida. An ambient temperature of 26° F represents the winter seasonal site minimum temperature and corresponds to maximum heat input and power generation. An ambient temperature of 73° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 100° F represents the summer seasonal maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. An ambient temperature of 59° F represents ISO conditions.

The maximum pound per hour emission rates (rounded to the nearest tenth of a pound) considering all ambient temperatures are presented in Table 2-1.

2.3.2 Natural Gas Auxiliary Boiler

The natural gas auxiliary boiler will be capable of firing natural gas only. The auxiliary boiler will have a heat input rate of approximately 7.2 mmBtu/h. The potential emissions from this emissions unit are based on unlimited operation. Projected emissions from the auxiliary boiler are based on vendor data representative of the type and size of the unit to be installed.

Table 2-1
CTG/HRSG Maximum Emission Rates (lb/h)*

Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO_x	17.5	81.1
SO_2	13.6	6.3
CO	52.3	92.4
PM/PM_{10} (front half only)	14.7	22.5
PM/PM_{10}** (front and back half)	38.0	52.0
VOC	5.1	10.2
SAM	6.1	3.5

*Maximum pound per hour emission rates (rounded to the nearest tenth of a pound) for the CCCT with duct firing considering site ambient temperatures and partial load operation.
**Includes the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

2.3.3 Diesel Engine Fire Pump

The diesel engine fire pump is considered emergency equipment and as such is considered exempt from permitting in accordance with Rule 62-210.300(3). This is discussed further in Section 2.6.3. While this emissions unit is exempt from permitting, its' emissions are still included in the potential to emit for the Project and in the AQIA. The diesel engine fire pump will fire ULS fuel oil. In determining the potential annual emissions, based on National Fire Protection Association (NFPA) guidelines it is conservatively estimated that the diesel engine fire pump will operate approximately 200 hours per year. Projected emissions from the diesel engine fire pump are based on vendor data representative of the type and size of the unit to be installed.

2.3.4 Safe Shutdown Generator

The safe shutdown generator will fire only ULS fuel oil. The generator will be subject to occasional testing to assure operability and used for service only when the transmission connection is lost and the plant shutdowns. When the transmission lines are lost (plant goes black), the generator would start to provide power to maintain the plant in a safe shutdown condition. It will only be run for short test periods when the plant is running, and will otherwise operate only when the plant in down and offsite power is lost.

As with the diesel engine fire pump, it is estimated that the safe shutdown generator will operate approximately 200 hours per year.

2.3.5 Fuel Oil Storage Tank

The fuel oil storage tank will have a capacity of approximately 990,000 gallons. Volatile Organic Compound (VOC) emissions from the fuel oil storage tank were estimated using the EPA TANKS 4.0 program. Results of the TANKS emission program are included in Appendix C. The VOC emissions from the fuel oil storage tank are approximately 0.16 tons per year (tpy). In accordance with Rule 62-210.300(3)(b)1., F.A.C., the fuel oil storage tank is exempt from the requirement to obtain an air construction permit. However, the fuel oil storage tank VOC emissions were included in the Project potential to emit estimates and information on the tank is included in the application forms.

2.3.6 Mechanical Draft Cooling Tower

The cooling tower water is expected to be wastewater treatment plant reclaimed water that has received high level treatment ("high level" disinfectant). Dissolved solids found in cooling tower drift typically consist of naturally occurring mineral matter, chemicals for corrosion inhibition, etc. Particulate matter is emitted when the drift droplets dispersed in the atmosphere evaporate and leave airborne fine particulate matter formed by crystallizations of dissolved solids.

Based on the type and efficiency of drift eliminators, drift droplets of varying sizes containing dissolved solids can be generated. Studies published by the Cooling Tower Institute have also pointed out that large drift droplets, if emitted, settle out of the tower exhaust air stream and deposit on the ground near the tower. This portion of the drift does not result in particulate matter emissions. Smaller drift droplets may be dispersed in the air and consequently, may evaporate before being deposited in the area surrounding the tower, resulting in emissions of particulate matter. For the purpose of this project, it is assumed that 100 percent of the drift droplets are small enough such that all the drift generated will be dispersed and lose water due to evaporation, resulting in emissions of particulate matter. PM emissions at a circulating water TDS loading of 5,331 ppm were determined to be 6.49 tons per year.

The United States Environmental Protection Agency AP-42 document (Section 13.4) provides a low quality emission factor for estimating PM_{10} emissions from cooling towers. Basically, the AP-42 document assumes that all PM emitted is PM_{10}. FMPA is proposing to use the approach outlined by Reisman and Frisbie to calculate a more realistic PM_{10} emission rate. The paper by Reisman and Frisbie can be found in

Appendix D for reference. This paper points out that at high concentrations of TDS in the circulating water, particulates formed by the mineral matter left after evaporation of moisture from the water droplets will have a higher fraction of particulate greater than 10 microns in diameter than at lower concentrations of TDS. In other words, not all PM emissions are PM_{10}. As TDS increases, total PM emissions increase by virtue of higher TDS. However, the mass fraction of PM_{10} relative to total PM will decrease because at higher TDS levels, a greater amount of solid particles are larger than 10 microns in diameter.

Based on the design parameters listed in Table 2-1, the PM_{10} emission estimate procedure outlined in the above referenced document, and Electric Power Research Institute (EPRI) cooling tower test facility data on droplet size distribution (also referenced in the Resiman and Gordon paper), it was determined that at a design recirculating water TDS of 5,331 ppm 27.68 percent of PM mass emissions from the proposed cooling tower are equal to or smaller than PM_{10}. This would result in a total PM_{10} emissions rate of 1.80 tpy. As a conservative estimate of PM_{10} emissions the TDS value which results in the highest PM_{10} emissions was used to estimate the potential emissions from the cooling tower. The maximum PM_{10} emissions rate was found to correspond with a TDS value of 3,918 ppm. Based on a circulating water TDS loading of 3,918 ppm and the calculated 39.14 percent of PM is PM_{10}, maximum PM_{10} emissions were determined to be 1.87 tpy. These calculations are presented in Appendix A. Please note that the EPRI drift spectrum was based on a drift eliminator that achieved a tested drift rate of 0.0003 percent. Since the proposed cooling tower has a proposed 0.0005 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate will produce smaller droplets. Therefore, the EPRI droplet size distribution data can be assumed to be conservative for predicting the fraction of PM_{10} in the total PM emissions from the proposed cooling tower.

2.4 Maximum Project Potential to Emit

The potential to emit (PTE) for Unit 1 was estimated based on the maximum hourly emission rate for each pollutant at an ambient temperature of 73° F (average annual temperature), considering operation from 40 to 100 percent load, unlimited operation on natural gas and up to 500 hours per year of operation on ULS fuel oil. The PTE for Unit 1 includes the use of the Best Available Control Technology (BACT). BACT for the emissions of NO_x is the use of low-NO_x burners and a SCR system while firing natural gas and the use of water injection and an SCR system when firing fuel oil. The use of natural gas and ULS fuel oil (0.0015 percent sulfur) is considered BACT control for PM/PM_{10}, SO_2, and sulfuric acid mist. Good combustion control is BACT for

CO emissions. The Unit 1 PTE for each pollutant is based on the worst case operating scenario for that pollutant. Therefore, the operating scenario used to calculate the PTE for one pollutant is not necessarily the same operating scenario used to determine the PTE for other pollutants.

The PTE for the auxiliary boiler, the diesel engine fire pump, the safe shutdown generator, the cooling tower and the fuel oil storage tank are also included in the Project's PTE. The auxiliary boiler, diesel engine fire pump, and safe shutdown generator PTE are based on vendor data for the approximate size and type of units that will be installed as part of the Project. The auxiliary boiler PTE is based on unlimited operation. Based on National Fire Protection Association (NFPA) guidelines it is conservatively estimated that the diesel engine fire pump will operate approximately 200 hours per year, and this level of operation was used to determine it's PTE. Similarly, it is conservatively estimated that the safe shutdown generator will operate approximately 200 hours per year, and this level of operation was used to determine its PTE. The fuel oil storage tank potential emissions were determined using the EPA TANKS program. The calculation of the cooling tower emissions is discussed in Subsection 2.3.6. The Project's PTE for each pollutant is summarized in Table 2-2. The footnotes in Table 2-2 provide the basis for the PTE values. The applicable PSD significant emission levels for each pollutant are also included in Table 2-2 for reference purposes.. The printout from a spreadsheet used to calculate the potential to emit is included in Appendix A.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) New Source Review (NSR) provisions are implemented for new major stationary sources and major modifications under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 Code of Federal Regulations (CFR) 51 and 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program will apply to the Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

Table 2-2
PSD Applicability

Pollutant	Project PTE[a] (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	90.0[b]	40	Yes
SO_2	56.6[c]	40	Yes
CO	231.0[b]	100	Yes
PM	176.1[b,d,e]	25	Yes
PM_{10}	171.4[b,d,e]	15	Yes
VOC	23.4[b,f]	40	No
Sulfuric Acid Mist	22.4[c,g]	7	Yes
Total Reduced Sulfur	negl.	10	No
Hydrogen Sulfide	negl.	10	No
Vinyl Chloride	negl.	1	No
Total Fluorides	negl.	3	No
Mercury	0.001[b,h]	0.1	No
Lead	0.007[b,h]	0.6	No

[a]Regardless of operating mode, emissions are based on operation of the combustion turbine at 100 percent load and at an average ambient temperature of 73° F and includes emissions from the duct burner. Includes emissions from the auxiliary boiler, the diesel engine fire pump, and the safe shutdown generator.
[b]Based on firing ULS fuel oil for 500 hours per year in the combustion turbine and firing natural gas for the remainder of the year.
[c]Based on firing natural gas in the combustion turbine for the entire year. Based on a natural gas sulfur content of 2 grains/100 scf.
[d]Includes the effects of SO_2 oxidation and formation of ammonium sulfates.
[e]Includes front and back half PM/PM_{10} emissions from the CCTG. Includes emissions from the cooling tower.
[f]VOC PTE is based on potential emissions from the Project's combustion source and emissions from the fuel oil storage tank
[g]Includes the effects of SO_2 oxidation and assumes 100 percent conversion of SO_3 to sulfuric acid mist (H_2SO_4).
[h]Based on AP-42 emission factors.
Note: PTE calculations are provided in a spreadsheet included in Appendix A.

2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS), while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at existing major sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The proposed Treasure Coast Energy Center is one of the 28 listed major source categories, and it therefore has a 100 tpy PSD major source threshold. Because the potential to emit of the Project is greater than 100 tpy for at least one PSD pollutant, PSD review is required for all pollutants for which the potential to emit is greater than the PSD significant emissions levels. The estimated potential emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project exceed the PSD significant emissions levels of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, PM/ PM_{10}, and SAM are subject to PSD review. Because emissions of VOC are below the PSD significant emissions level of 40 tpy, the Project is not subject to PSD review for VOCs. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the Project's total impact on general residential and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis. These analyses are included in Sections 3.0, 4.0, and 5.0.

2.6 Regulatory Review

This section provides a review of rule applicability for the various emission units that are a part of the Project.

2.6.1 Rule Applicability to Unit 1

The following Sections include a discussion of the applicability of regulations to the Unit 1 combustion turbine and/or the duct burner.

2.6.1.1 CT MACT. On March 5, 2004, the United States Environmental Protection Agency (EPA) published final national emission standards for hazardous air pollutants (NESHAP) for stationary combustion turbines. This rule, found at 40 CFR Part 63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of hazardous air pollutants (HAPs). A major source of HAPs is a site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. Potential HAP emissions at the facility were estimated using USEPA AP-42 emission factors. The following emission units were included in the HAP emissions analysis:

- The combustion turbine.
- The HRSG duct burner.
- The auxiliary boiler.
- The diesel engine fire pump.
- The safe shutdown generator.

The potential to emit for any combination of HAP at the Treasure Coast Energy Center is 12.5 tons per year. The maximum potential to emit of any single individual HAP is 5.5 tons per year of formaldehyde. It should be noted that these emission calculations are based on AP-42 emission factors, which are believed to provide a very conservative estimate of HAP emissions from the type of combustion turbine to be installed at the Treasure Coast Energy Center. Using this conservative basis, the potential to emit level is well below the HAP major source levels, and as such, the site is not a major source of HAPs. Because the site is not a major source of HAPs, the CT MACT standard does not apply to Unit 1. Spreadsheets showing the HAP emission calculations for the Project are included in Appendix A.

2.6.1.2 New Source Performance Standards (NSPS). The combustion turbine is subject to the *Standards of Performance for Stationary Gas Turbines*, as revised July 8, 2004. This type of standard is commonly referred to as a New Source Performance Standard (NSPS). This NSPS is found at 40 CFR 60 Subpart GG and is adopted by reference in Rule 62-204.800(8)(b)39, F.A.C.

The duct burner is subject to the *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*. This NSPS is found at 40 CFR 60 Subpart Da and is adopted by reference in Rule 62-204.800(8)(b)2, F.A.C.

As a proposed new NSPS standard, published in the Federal Register on February 18, 2004, the *Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005 or for Which Modification or Reconstruction is Commenced on or After [Date 6 Months After Date Final Rule is Published in the Federal Register]* will be applicable to Unit 1, when/if it becomes final, if it becomes final as proposed. This NSPS will be found at 40 CFR 60 Subpart KKKK when/if it is made final.

When/if the proposed NSPS Subpart KKKK becomes final, if it becomes final as proposed, the Unit 1 combustion turbine will not be subject to NSPS Subpart GG. As stated in 40 CFR 60.4305(b) of proposed Subpart KKKK, stationary combustion turbines regulated under 40 CFR 60 Subpart KKKK are exempt from the requirements of 40 CFR 60 Subpart GG.

Proposed revisions to NSPS Subpart Da, *Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, were published in the Federal Register on February 28, 2005. Under 60.40a(b) of the proposed Subpart Da revisions and under 40 CFR 60.4305(b) of proposed Subpart KKKK, heat recovery steam generators and duct burners regulated under Subpart KKKK are exempted from the requirements of 40 CFR 60 Subpart Da. Therefore, when/if finalized, under proposed NSPS Subpart KKKK and proposed revisions to NSPS Subpart Da, the Unit 1 duct burner will not be subject to NSPS Subpart Da.

2.6.2 Rule Applicability to the Natural Gas Auxiliary Boiler

The *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, NSPS Subpart Dc, applies to each steam generating unit that has a maximum design capacity of 100 mmBtu/h or less, but greater than 10 mmBtu/h. Because the Project natural gas auxiliary boiler has a maximum heat input rate of less than 10 mmBtu/h, it is not subject to 40 CFR Subpart Dc.

The natural gas auxiliary boiler is subject to Rule 62-296.406, F.A.C., *Fossil Fuel Steam Generators with Less Than 250 Million Btu Per Hour Heat Input, New and Existing Emission Units.* By this rule the auxiliary boiler is subject to a 20 percent opacity standard and is required to implement BACT for PM and SO_2. As discussed in Section 3, the use of natural gas and good combustion practices is considered BACT for this emissions unit.

2.6.3 Rule Applicability for the Diesel Engine Fire Pump

There are no NSPS regulations applicable to this emissions unit. The *National Emission Standards for Reciprocating Internal Combustion Engines* MACT standard is only applicable to emission units at a facility that is a major source of HAPs. This MACT standard is found at 40 CFR 63 Subpart ZZZZ. As discussed in Section 2.6.1.1, the Energy Center will not be a major source of HAPs, and as such 40 CFR 63 Subpart ZZZZ does not apply to this emissions unit. None of the standards included in 62-296, F.A.C. apply to the diesel engine fire pump.

Because the diesel engine fire pump falls under the categorical emission unit exemption given at Rule 62-210.300(3)(a)22, F.A.C. for fire and safety equipment, the diesel engine fire pump is exempt from the preconstruction review permitting requirements of Chapter 62-212, F.A.C. The diesel engine fire pump is included in the list of exempt emission units given in Attachment G of the application forms. While the diesel engine fire pump is considered exempt from permitting requirements, the projected potential emissions are included in the Project potential to emit calculations and its' emissions were included in the ambient air quality impact analysis (AAQIA). A set of emissions unit information forms for this emissions unit is also included with the application forms.

2.6.4 Rule Applicability for the Safe Shutdown Generator

There are no NSPS regulations applicable to this emissions unit. The *National Emission Standards for Reciprocating Internal Combustion Engines* MACT standard is only applicable to emission units at a facility that is a major source of HAPs. This MACT standard is found at 40 CFR 63 Subpart ZZZZ. As discussed in Subsection 2.6.1.1, the new Energy Center will not be a major source of HAPs, and as such 40 CFR 63 Subpart ZZZZ does not apply to this emissions unit. None of the standards included in 62-296, F.A.C. apply to the safe shutdown generator.

2.6.5 Rule Applicability to the 990,000 Gallon Fuel Oil Storage Tank

The fuel oil storage tank to be added as part of the Project is estimated to have a capacity of slightly less than 990,000 gallons. The *Standards of Performance for volatile organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*, as revised October 15, 2003, does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa. This NSPS is found at 40 CFR 60 Subpart Kb and is adopted by reference in Rule 62-204.800(8)(b)16, F.A.C. Because the vapor pressure of ULS fuel oil is less than 3.5 kPa, this storage tank is not subject to 40 CFR 60 Subpart Kb. None of the standards included in 62-296, F.A.C. apply to the fuel oil storage tank.

Because the fuel oil storage tank meets the criteria of 62-210.300(3)(b)1, the fuel oil storage tank is considered exempt from the preconstruction review permitting requirements of Chapter 62-212, F.A.C. The fuel oil storage tank is included in the list of exempt emission units given in Attachment G of the application forms. However, potential emissions from this emissions unit are included in the Project PTE calculations to ensure that the emissions from this emissions unit would not cause the Project PTE to exceed the PSD significant emissions level for VOCs. A set of emissions unit information forms for this emissions unit is also included with the application forms.

2.6.6 Rule Applicability for the Mechanical Draft Cooling Tower

There are no MACT standards or NSPS standards that apply to the cooling tower. None of the standards included in 62-296, F.A.C. apply to the cooling tower.

2.6.7 Excess Emissions

As with other combined cycle combustion turbines of this size and type, excess emissions during startup, shutdown and malfunction are likely to exceed the duration of excess emissions allowed per Rule 62-210.700(1), F.A.C. In accordance with Rule 62-210.700(5), F.A.C., FMPA is requesting that the air permit for the Project allow for excess emissions from startups and shutdowns greater than 2 hours per 24 hour period. FMPA requests that a condition similar to condition 15 of the APPLICABLE STANDARDS AND REGULATIONS Section of the Florida Power & Light Turkey Point Unit 5 permit issued by FDEP on February 8, 2005 be included in the Project permit. In general, it is requested that in a 24 hour period, this condition allow for six hours of excess emissions during a cold start of the steam turbine/HRSG system, four hours of excess emissions during a warm start of the steam turbine/HRSG, three hours of excess emissions for the shutdown of the combined cycle operation and one hour of excess emissions for a fuel switch. It is also requested that in the event there is a trip during a startup or during a 24-hour period that contains a startup, the permit allows for additional excess emissions during a startup subsequent to a unit trip (i.e. the allowable excess emissions clock starts over after a unit trip which results in the need to restart the unit).

2.6.8 DLN Tuning

As allowed in the Florida Power & Light Turkey Point Unit 5 permit issued by FDEP on February 8, 2005, FMPA is requesting that the permit for this project allow for exclusion of CEMS data collected during initial or other major DLN tuning sessions from the CEMS compliance demonstration. FMPA is requesting that a condition similar to condition 16 of the APPLICABLE STANDARDS AND REGULATIONS Section of the Florida Power & Light Turkey Point Unit 5 permit issued by FDEP on February 8, 2005 be included in the Project permit. The following is example permit language:

> "DLN Tuning: Excess emissions of NOx, CO, and opacity is allowed during DLN tuning sessions. CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a

combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]"

3.0 Best Available Control Technology

A best available control technology (BACT) analysis for the Project has been included as Appendix E. Emissions for the BACT analysis are based on unlimited natural gas firing for Unit 1 and an average ambient temperature of 78° F. The following is a summary of the BACT determination for Unit 1.

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of low-NO_x burners and an SCR to achieve 2 ppmvd at 15 percent O_2 when firing natural gas and the use of water injection and an SCR to achieve 8 ppmvd at 15 percent O_2 when firing ULS fuel oil.
- Carbon monoxide (CO) emissions--BACT was determined to be the use of good combustion practices when firing either natural gas or ULS fuel oil.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and the use of natural gas and ULS fuel oil with less than 0.0015 percent sulfur by weight.
- Volatile Organic Compounds (VOC) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of natural gas and ULS fuel oil with less than 0.0015 percent sulfur.
- Sulfur acid mist (H_2SO_4) emissions--BACT was determined to be the use of natural gas and ULS fuel oil with less than 0.0015 percent sulfur.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those PSD pollutants which will have a PTE greater than the PSD significant emission rate (i.e. CO, NO_x, PM/PM_{10}, and SO_2). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of FMPA in a letter from Black & Veatch dated January 7, 2005. The FDEP provided approval of the protocol via email on January 13, 2005. Comments on the protocol were provided by EPA Region 4 via FDEP on February 7, 2005. Responses to the EPA comments were provided to FDEP on February 18, 2005. On February 22, 2005 FDEP responded that the EPA indicated that all of the responses to their comments were appropriate. The National Park Service (NPS) provided comments on the Class I protocol on February 28, 2005. A response to the NPS comments was provided to FDEP on March 3, 2005. A copy of the protocol, correspondence indicating FDEP and EPA approval of the protocol, and correspondence regarding the NPS comments are presented in Appendix F.

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 02035) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels, and ambient temperatures. Performance data for the combustion turbine operating with separate fuels (natural gas and ultra low sulfur fuel oil) at several different loads (40, 50, 75, and 100 percent) over a range of ambient temperatures (26, 59, 73, and 100° F) are included in Appendix B. The corresponding stack parameters and emission rates for each load and ambient temperature considered in the analysis are presented in Table 4-1. For the 100 percent load cases, the parameters in Table 4-1 are "enveloped" over the different operating scenarios as provided in Appendix B. "Enveloping" is the process in which a representative set of stack parameters and pollutant emission rates are utilized to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperature and exit velocity and the highest emission rate).

Emissions from the auxiliary boiler, diesel engine fire pump, safe shutdown generator, and the cooling tower were also included in the modeling. Emissions data for these emission units are included in Appendix A. Because the diesel engine fire pump and the safe shutdown generator are only operated in emergency situations and for occasional testing to ensure operability, emissions from these units in the modeling are based on operating 1 hour per day and 200 hours per year.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the proposed Project's location, it was concluded that over 50 percent of the area surrounding the Project is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. Building and structure dimensions, as well as relative locations, were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for the combined cycle Unit 1 stack is 64.01 m (210 ft). The proposed Project stack height is 51.81 m (170 ft). As such, direction-specific downwash parameters from the BPIP program were included in the ISCST3 air dispersion modeling analysis.

Table 4-1
Stack Parameters and Pollutant Emissions
Used in ISCST3 Modeling Analysis

Fuel[a]	Load	Ambient Temperature (°F)	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
							NO_x	SO_2	PM/PM_{10}[b]	CO
NG	100	100	170	18	58	166	16.10	12.55	38.00	49.20
		73	170	18	63	168	16.50	12.89	38.00	50.10
		59	170	18	64	166	16.90	13.20	38.00	51.40
		26	170	18	68	167	17.50	13.64	38.00	52.30
	75	100	170	18	48	173	9.60	7.45	22.60	22.00
		73	170	18	51	172	10.20	7.97	23.00	23.00
		59	170	18	51	169	10.40	8.18	23.10	24.00
		26	170	18	53	167	11.10	8.60	23.40	25.00
	50	100	170	18	40	167	7.60	5.93	21.70	18.40
		73	170	18	42	164	8.00	6.36	22.00	19.10
		59	170	18	42	161	8.30	6.54	22.10	20.00
		26	170	18	43	158	8.70	6.89	22.30	20.30
	40	100	170	18	37	165	6.70	5.26	19.00	52.30
		73	170	18	38	162	7.10	5.61	19.00	52.30
		59	170	18	38	158	7.30	5.76	19.00	18.00
		26	170	18	39	155	7.80	6.08	19.00	18.40

Table 4-1 (Continued)
Stack Parameters and Pollutant Emissions
Used in ISCST3 Modeling Analysis

Fuel[a]	Load	Ambient Temperature (°F)	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
							NO_x	SO_2	PM/PM_{10}[b]	CO
FO	100	100	170	18	68	249	73.20	5.91	51.20	82.30
		73	170	18	74	251	76.00	6.04	49.90	86.20
		59	170	18	76	251	78.00	6.17	52.00	88.70
		26	170	18	81	252	81.10	6.29	50.00	92.40
	75	100	170	18	56	250	45.00	2.19	35.40	49.00
		73	170	18	58	248	48.00	2.34	35.50	51.00
		59	170	18	60	245	49.80	2.42	36.20	52.50
		26	170	18	62	247	52.00	2.52	35.60	54.20
	50	100	170	18	46	243	35.10	1.72	35.10	41.10
		73	170	18	48	243	37.60	1.84	35.10	43.00
		59	170	18	49	243	39.30	1.91	35.70	43.50
		26	170	18	50	243	40.70	1.99	35.20	45.00

[a]NG – Natural Gas, FO – Ultra Low Sulfur Fuel Oil.
[b]PM/PM_{10} represents both front and back half emissions. PM/PM_{10} emissions for natural gas firing 40 percent load case are based on results of air dispersion modeling and engineering judgment.

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1 km, 250 m spacing from 1 to 2.5 km, 500 m spacing from 2.5 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing of 100 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. The flat terrain option was used for all receptor points. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission source and downwash structures.

4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1987-1991) of surface and upper air meteorological data from West Palm Beach were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, PM/PM_{10}, and CO. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the emission rates for NO_x, SO_2, PM/PM_{10}, and CO for each applicable averaging period. Table 4-2 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the pre-construction monitoring requirements. As Table 4-2 indicates, the Project's maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyse (i.e., PSD increment and Ambient Air Quality Standards analyses) are required. As the Projects' major source of emissions is the combustion turbine; for informational purposes, the maximum impacts from the combustion turbine without the contribution of the ancillary equipment are presented in Table 4-3.

If any of the maximum impact source groups from each pollutant and averaging period, or the controlling impacts (i.e., a concentration within 10 percent of the maximum impact) from such a source group, occurred at the edge of or beyond the 100 m fine grid, a 100 m refined receptor grid would be placed around the impact to ensure that an absolute maximum concentration was obtained from the model. This procedure was not required for any pollutants, as all of the maximum impacts and controlling impacts were within the 100 m fine grid.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

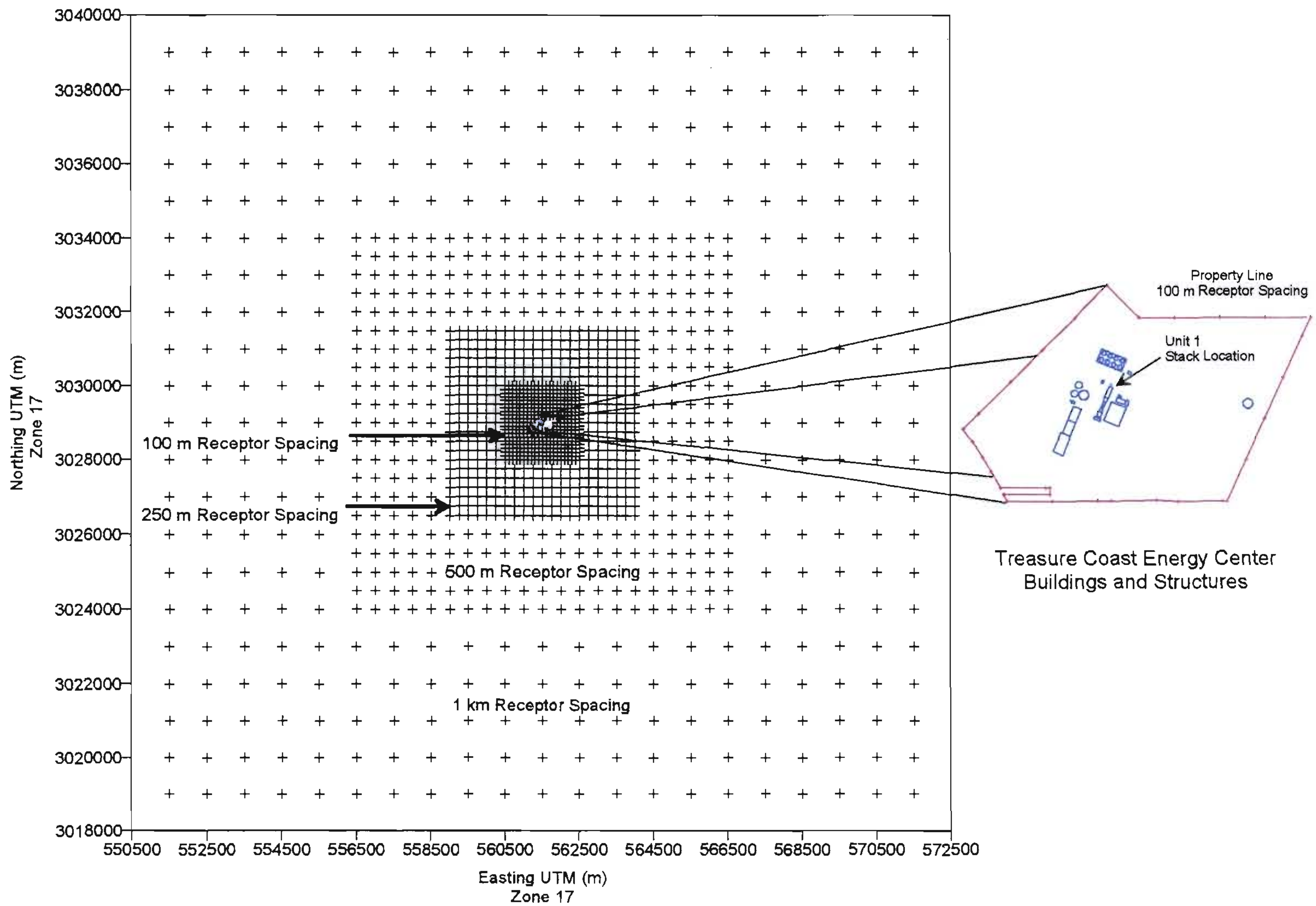

Figure 4-1
Receptor Location Plot

Table 4-2
ISCST3 Model-Predicted Class II Impacts

Pollutant	Averaging Period	Model-Predicted Impact[a] (μg/m³) Natural Gas 100%	Natural Gas 75%	Natural Gas 50%	Natural Gas 40%	Fuel Oil 100%	Fuel Oil 75%	Fuel Oil 50%	PSD Class II SIL[b] (μg/m³)	Exceed SIL?	De Minimis Monitoring Level[c] (μg/m³)	Pre-Construction Monitoring Required?
NO_x	Annual	0.61	0.62	0.64	0.65	0.61	0.63	0.66	1	NO	14	NO
SO_2	Annual	0.05	0.06	0.07	0.08	0.05	0.05	0.05	1	NO	--	NO
	24 Hour	1.21	1.15	1.35	1.39	0.37	0.37	0.37	5	NO	13	NO
	3 Hour	2.89	2.25	2.44	2.43	1.36	1.36	1.36	25	NO	--	NO
PM/PM_{10}[d]	Annual	0.20	0.22	0.27	0.30	0.20	0.20	0.23	1	NO	--	NO
	24 Hour	4.02	3.90	4.86	4.79	2.75	3.32	4.69	5	NO	10	NO
CO	8 Hour	10.45	10.34	10.34	18.51	10.34	10.34	10.34	500	NO	575	NO
	1 Hour	102.14	102.14	102.14	102.14	102.15	102.14	102.14	2,000	NO	--	NO

[a] Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data modeled at each corresponding load.
[b] Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c] This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.
[d] Note that the PM_{10} impacts are below the PSD Class II SILs and the NAAQS for $PM_{2.5}$ are significantly greater than the PM_{10} SILs. Therefore, if one were to conservatively assume that $PM_{2.5}$ impacts would be the same as the PM_{10} impacts, then the impacts would be significantly below the $PM_{2.5}$ NAAQS.

Table 4-3
ISCST3 Model-Predicted Combustion Turbine Impacts

Pollutant	Averaging Period	Model-Predicted Impact[a] (μg/m³)							PSD Class II SIL[b] (μg/m³)	Exceed SIL?
		Natural Gas				Fuel Oil				
		100%	75%	50%	40%	100%	75%	50%		
NO_x	Annual	0.040	0.030	0.051	0.066	0.090	0.071	0.093	1	NO
SO_2	Annual	0.031	0.023	0.040	0.052	0.007	0.003	0.005	1	NO
	24 Hour	1.106	1.080	1.264	1.297	0.180	0.164	0.197	5	NO
	3 Hour	2.818	2.184	2.372	2.359	0.640	0.379	0.410	25	NO
PM/PM_{10}	Annual	0.095	0.066	0.142	0.168	0.063	0.053	0.093	1	NO
	24 Hour	3.347	3.221	4.182	4.117	1.563	2.641	4.016	5	NO
CO	8 Hour	8.519	4.971	5.634	16.58	4.338	6.112	7.185	500	NO
	1 Hour	16.38	9.219	9.629	27.53	16.42	12.93	13.99	2,000	NO

[a]Impacts represent the highest first high model-predicted concentration from all five years of meteorological data modeled at each corresponding load.
[b]Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.

5.0 Additional Impact Analyses

The following sections discuss the proposed Project's impacts upon commercial, residential, and industrial growth, as well as vegetation and soils, and the nearest Federal Class I area.

5.1 Commercial, Residential, and Industrial Growth

The proposed project is to be located at the new Treasure Coast Energy Center near Fort Pierce, St. Lucie County, Florida. Because the proposed project is being installed to meet the existing and current projected electrical demands of the surrounding area, it is anticipated that little growth will be associated with its operation. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. According to the US Census Bureau, the population of St. Lucie County has grown by 28.3 percent between the 1990 and 2000 censuses. In line with the population growth, the net number of new, permanent jobs which will be created by the Project is estimated to be little to none. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the Project will be very small, compared to the overall existing population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the Project's impacts on soils and vegetation will be minimal.

The AAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations of NO_2, SO_2, and PM/PM_{10} below the secondary AAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants which triggered an additional impact analysis include NO_x, SO_2, and PM/PM_{10}. The modeled impacts were compared to the secondary AAQS as the basis for assessing impacts. It can be inferred from the modeling in Section 4.0 that the NO_x, SO_2, and PM/PM_{10} impacts are below the AAQS. The impacts are even less than the much lower significant impact level thresholds. Because the Project's emissions do not significantly impact the AAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

As part of the air impact evaluation for the proposed Project, analyses of the Project's effect on both the Everglades National Park (ENP) and the Chassahowitzka Wilderness Area (CWA) were performed. The ENP is a PSD Class I area located in southern Florida, approximately 180 km south-southwest of the Project site. The CWA is a PSD Class I area located in central Florida along the Gulf of Mexico coast, approximately 260 km northwest of the Project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this analysis are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) were evaluated and compared to the recommended thresholds. Figure 5-1 presents the location of the proposed Project site with respect to the ENP and CWA.

The methodology of the California Puff (CALPUFF) analysis followed those procedures recommended in the National Park Service's (NPS) *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report* dated December 2000, Earth Tech, Inc.'s *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* dated September 2001, the *Long-Range-Transport Screening Technique Using CALPUFF* document jointly authored by the NPS and the EPA, and an air dispersion modeling protocol sent to FDEP in response to NPS comments (received February 28, 2005) on Black & Veatch's original protocol and subsequent responses to EPA comments, via email, on March 3, 2005 (Appendix F). The following sections include discussions of the air modeling approach to assess impacts at ENP and CWA as well as the model-predicted impacts from the Project onto the ENP and CWA.

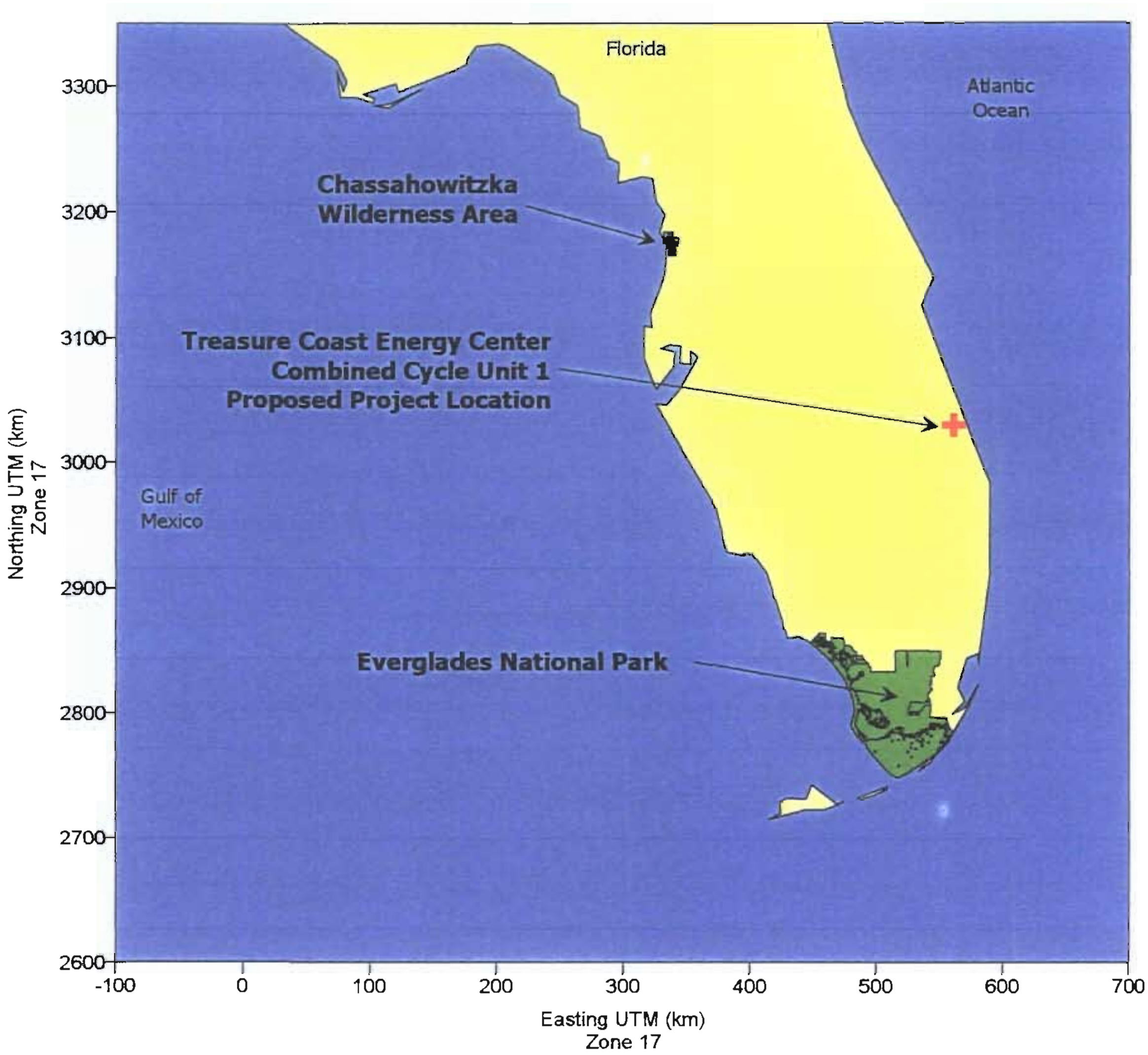

Figure 5-1
Proposed Project Location with Respect to
Everglades National Park & Chassahowitzka Wilderness Area

5.3.1 Model Selection

The CALPUFF (Version 5.711A, Level 040716) air modeling system was used to model the Project and assess the AQRVs at ENP and CWA. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. CALPUFF was used in the "screening mode" of the model commonly referred to as CALPUFF Lite. CALPUFF Lite utilizes a modified meteorological data file for use in the ISCST3 air dispersion model, thus bypassing the need to run CALMET, an involved model designed to generate a three dimensional wind field with USGS terrain and land use data files, while retaining the required conservatism of a screening model.

5.3.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.3.3 Building Wake Effects

The CALPUFF analysis included the proposed facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 04112, and included in the CALPUFF model input.

5.3.4 Receptor Locations

The CALPUFF ENP analysis used three rings of discrete Cartesian receptors located at a distance equal to that of the nearest, equidistant, and farthest boundary of ENP and the location of the Project. Specifically, the rings consists of receptor spacing of every 1-degree (i.e., 360 receptors per ring) beginning with the closest ring at a 181.1 km distance from the Project, the intermediate ring at a 232.6 km distance from the Project, and the farthest ring at a distance of 284.1 km. The elevation for all of the discrete Cartesian receptors were conservatively assumed to equal the maximum elevation representative of the ENP in the database of discrete receptors created and distributed by the NPS for standardized use in refined Class I analyses. The maximum elevation presented in the array of discrete Cartesian receptors in the NPS database for ENP was 1 meter and was applied to each receptor on all three rings effectively representing ENP in every direction from the Project. Receptor rings serve to introduce conservatism into screening level modeling.

Table 5-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, $PM_{0.05}$, $PM_{0.10}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.00}$
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	ISC type data processed for wet deposition
Plume Rise	Stack-tip downwash
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24 hour change as processed by CALPOST. Deposition: Highest predicted annual total sulfur and nitrogen values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 10 ppb; Monthly Ozone: 80 ppb

Due to the area's small size, the CALPUFF CWA analysis used two rings of discrete Cartesian receptors located at a distance equal to that of the nearest and farthest boundary of CWA and the location of the Project. Specifically, the closest ring consists of receptor spacing of every 1-degree beginning at a 260.5 km distance from the Project, while the farthest ring begins at a distance of 274.7 km with receptor spacing of every 1-degree. The elevation for all of the discrete Cartesian receptors were conservatively assumed to equal the maximum elevation representative of the CWA in the NPS database of discrete receptors of Class I areas. The maximum elevation presented in the array of discrete Cartesian receptors in the NPS database for CWA was 3 meters and was applied to each receptor on the two rings effectively representing CWA in every direction from the Project.

5.3.5 Modeling Domain.

The size of the domain used for the modeling was based on recommendations found in the guidance document *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II*, dated December 1998. Specifically, the guidance document states that the domain should extend at least 50 km beyond the outer most receptor ring in each of the north, south, east, and west directions to allow for puffs to return to a Class I area due to a recirculating wind pattern.

Since the screening methodology uses meteorological data from a single ISC meteorological data file, there is no spatial variation in meteorological or geophysical properties. Therefore, the minimum grid cell configuration of 2 grid cells in the x-direction and 2 grid cells in the y-direction was used (4 grid cells total). A single layer was used in the vertical since wind speed measurements taken at anemometer height will be scaled to stack-top height, as in ISC. Therefore, the two cell face heights were set to 0 meters (ground-level) and 5,000 meters.

The outer most receptor rings extended 284.1 km and 274.7 km from the Project site for the ENP and CWA, respectively. Since the CWA domain was completely encompassed by the ENP domain, only one domain was utilized in the modeling analysis. The resulting grid cells are 334.1 km on a side, producing a 50-km buffer for ENP and a 59.4-km buffer for CWA. The modeling analysis was performed in the UTM coordinate system. The southwest corner of the domain is the origin and is located at 227.416 km Easting and 2,694.896 km Northing (based on UTM Zone 17, North American Datum (NAD) 1927 coordinates). Figures 5-2 and 5-3 illustrate the size and location of the modeling domain and associated receptors with respect to ENP and CWA, respectively.

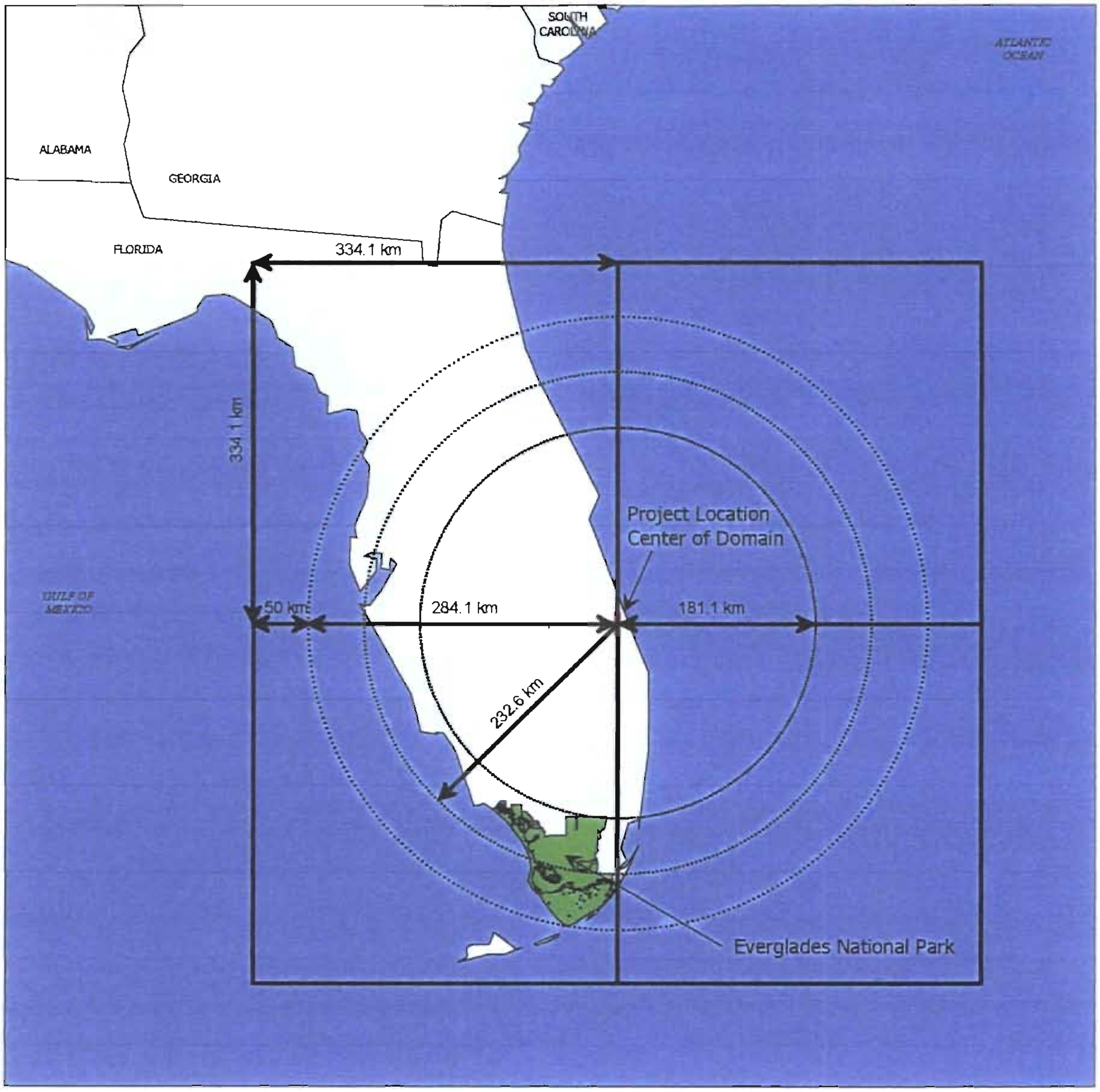

Figure 5-2
Modeling Domain

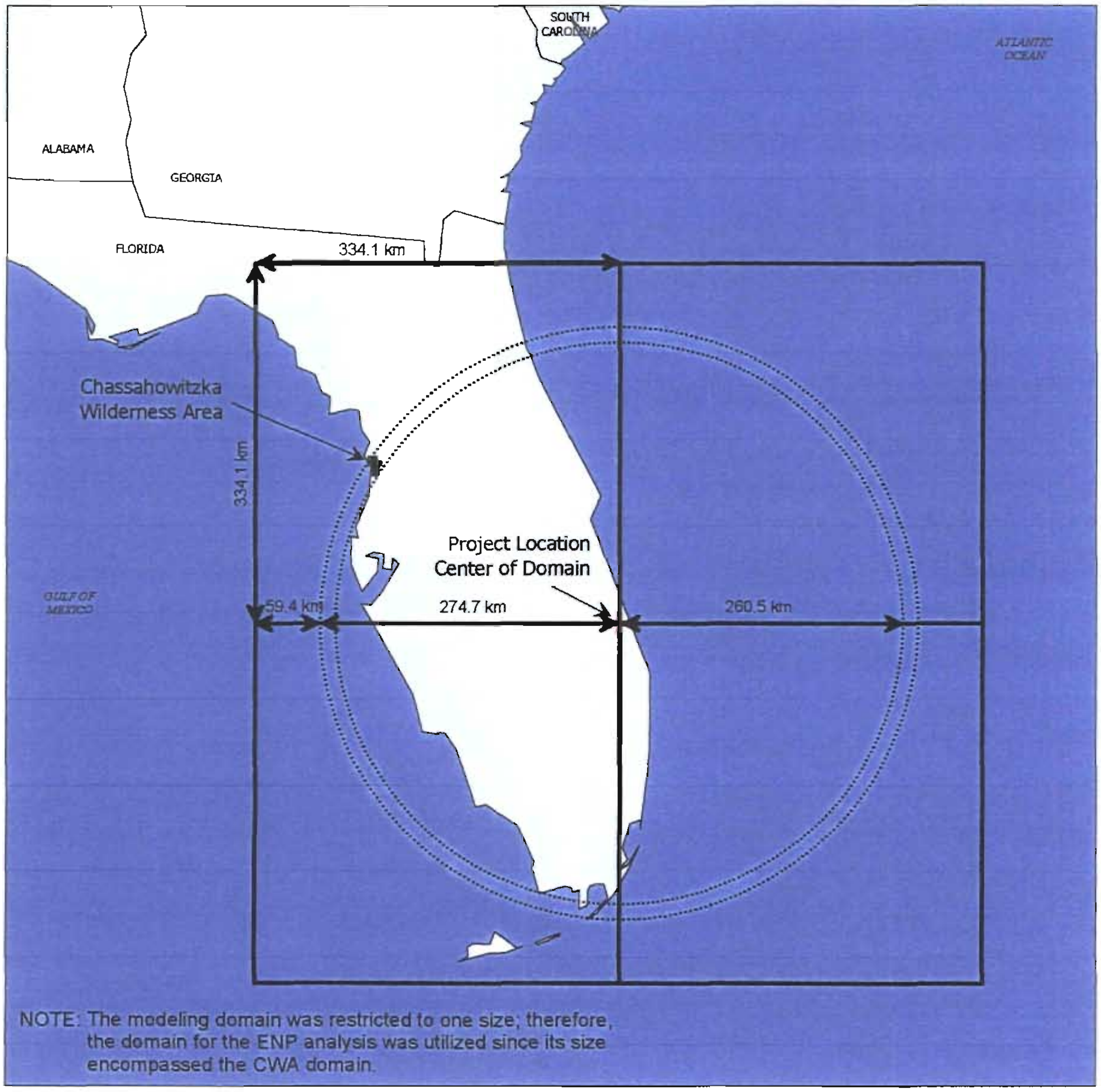

Figure 5-3
Modeling Domain

5.3.6 Meteorological Data

The meteorological data that was used in the CALPUFF Lite model consisted of five years (1987-1991) of National Weather Service data. The data set included surface observations and upper air, twice-daily mixing height data for West Palm Beach, Florida, downloaded from the EPA's SCRAM website. The data were processed with CPRammet to give CALPUFF enough information to perform the Mesopuff II chemistry transformations. CPRammet is a modified version of the EPA meteorological processor PCRammet. It was created by Earth Tech, the developers of the CALPUFF modeling system. CPRammet was designed to alleviate two incompatibilities between PCRammet and the CALPUFF model: 1) PCRammet will not produce the necessary extended ISCST3 variables (e.g., friction velocity, Monin-Obukhov length, relative humidity, solar radiation, etc.) when input data are in CD-144 format and 2) PCRammet will not report solar radiation when an observed value is missing.

The data were processed with CPRammet for wet deposition to produce the necessary extended ISCST3 variables. Values for surface roughness, albedo, Bowen ratio (average moisture), Monin-Obukhov length, and net radiation absorbed at the ground were derived from the June 1999 PCRammet User's Guide. For values where the specific land use type was required (i.e., surface roughness, albedo, and average moisture Bowen ratio), the Grassland land use category was chosen and averaged over the 4 seasonal values provided to arrive at a single annual value for input into CPRammet. For the Monin-Obukhov length, the Open Agricultural land use type and subsequent 2 meter value was used. For the net radiation absorption value, the rural value of 0.15 was chosen. As indicated in the user's guide, anthropogenic heat flux was assumed to be zero for areas outside highly urbanized locations.

5.3.7 Project Emissions

The worst-case representative stack parameters and pollutants emission rates at 100% operating load were used in the CALPUFF analyses. This was accomplished by representing the 100% operating load with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from performance data over a range of ambient temperatures (i.e., 26, 59, 73, and 105° F) to produce worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping".

Those pollutants modeled include NO_x, PM/PM_{10} (filterable and condensable), SO_2, and SO_4 (from $(NH_4)_2SO_4$). Table 5-2 contains the stack parameters and emission rates modeled in CALPUFF. Furthermore, per guidance from NPS, the PM/PM_{10} emissions were speciated based on size and composition and therefore were broken into the following constituents: elemental carbon (EC), organic carbon (OC), and soils

(SOIL) for the regional haze analysis. Specifically, guidance from NPS on particulate matter speciation was found in the Emissions & Control Technology area of their website. Per NPS, for natural gas fired combustion turbines, all the filterable portion of PM/PM_{10} emissions are considered EC and all non-$(NH_4)_2SO_4$ condensibles are considered to be OC. For fuel oil fired combustion turbines, half of all filterable PM/PM_{10} are considered EC, half of all filterable PM/PM_{10} are considered SOIL, and all non-$(NH_4)_2SO_4$ condensible PM/PM_{10} are considered OC.

The EC, OC, and SOIL emissions were further speciated based on size. Per NPS guidance, all particles were assumed to be one micron or less for combustion turbines. Table 5-3 presents size distribution for EC, OC, and SOIL particulates as recommended by NPS along with the Project's emission rates for each category and size.

Table 5-2
Stack Parameters and Pollutant Emissions
Used in CALPUFF Modeling Analysis

Fuel[a]	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)				
					NO_x	SO_2	PM/PM_{10}[b]	SO_4[c]	PM/PM_{10}[d]
NG	170	18	58.0	166.0	17.50	13.64	38.00	5.39	30.59
FO	170	18	68.0	249.0	81.10	6.29	52.00	3.42	47.31

[a]NG – Natural Gas, FO – Ultra Low Sulfur Fuel Oil.
[b]PM/PM_{10} represents both front and back half emissions including condensable $(NH_4)_2SO_4$. Used when comparing PM/PM_{10} impacts to Class I SILs.
[c]Represents the SO_4 portion of $(NH_4)_2SO_4$ emissions for the scenario that produced the maximum PM/PM_{10} emissions.
[d]Represents the portion of PM/PM_{10} available for speciation based on size and composition. Values derived by subtracting the $(NH_4)_2SO_4$ emissions from the PM/PM_{10} values.
NG: 38.00 lb/hr – 7.41 lb/hr of $(NH_4)_2SO_4$ = 30.59 lb/hr (3.854 g/s).
FO: 52.00 lb/hr – 4.70 lb/hr of $(NH_4)_2SO_4$ = 47.31lb/hr (5.961 g/s).

Table 5-3
Particle Size Distribution

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (g/s) [a]				
			Filterable	Non-$(NH_4)_2SO_4$ Condensible	Filterable		Non-$(NH_4)_2SO_4$ Condensible
			NG EC	NG OC	FO EC	FO SOIL	FO OC
PM0P05	0.05	15	0.268	0.310	0.213	0.213	0.469
PM0P10	0.10	25	0.447	0.516	0.354	0.354	0.781
PM0P15	0.15	23	0.412	0.475	0.326	0.326	0.718
PM0P20	0.20	15	0.268	0.310	0.213	0.213	0.469
PM0P25	0.25	11	0.197	0.227	0.156	0.156	0.344
PM1P00	1.00	11	0.197	0.227	0.156	0.156	0.344
Sub-Total			1.789	2.065	1.418	1.418	3.125
Total			3.854		5.961		

[a]NG – Natural Gas, FO – Ultra Low Sulfur Fuel Oil.

5.3.8 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the ENP and CWA, including regional haze, deposition, and Class I SILs.

5.3.8.1 Regional Haze Analysis. A regional haze analysis was performed for the ENP and CWA for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, EC, OC, and SOIL concentrations.

Visibility

Visibility is an AQRV for the ENP and CWA. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because both the ENP and CWA lie beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

- Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
- Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where:

b_{exts} = the extinction coefficient calculated for the source, and

b_{extb} = the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta \text{ percent} = (b_{exts} / b_{extb}) \times 100$$

Background Visual Ranges and Relative Humidity Factors

The background visual range and seasonal relative humidity factor were based on data representative of historical conditions at both the ENP and CWA, respectively. The background visual ranges, or constituents thereof, for both the ENP and CWA were obtained from the Phase I FLAG Report, December 2000.

Regional Haze Methodology

As provided for in the FLAG document, regional haze was calculated using Method 6, which consists of computing extinctions from speciated PM measurements using FLAG relative humidity adjustment factors applied to observed and modeled sulfate and nitrates. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24 hour SO_4, NO_3, EC, OC, and SOIL impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

   $(NH_4)_2SO_4$ (µg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4

   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

   NH_4NO_3 (µg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3

   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   b_{exts} = 3 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 10 x EC + 4 x OC + 1 x SOIL
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:

   $$b_{extb} = 3.912 / \text{Visual range (km)}$$
5. Compute the change in extinction coefficients:

   in terms of deciviews:

   $$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

   in terms of percent change of visibility:

   $$\Delta \text{ percent} = (b_{exts} / b_{extb}) \times 100$$

Based on the predicted SO_4, NO_3, and EC, OC, and SOIL concentrations, the proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5. As illustrated in Table 5-5, the regional haze results, reported as the maximum value occurring anywhere on the respective receptor rings for each Class I area, are less than the 5 percent change in extinction threshold for both the ENP and the CWA and, as such, no further analysis is necessary.

Table 5-5
Regional Haze Results

Class I Area	Change in Extinction[a] (%)		Recommended Threshold (%)
	Natural Gas	Fuel Oil	
Chassahowitzka WA	1.23	1.94	5
Everglades NP	1.80	2.76	5

[a]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

5.3.8.2 Deposition Analyses. Deposition analyses were performed for ENP and CWA for both total sulfur and total nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses were performed as follows:

- Perform CALPUFF model runs using the specified options previously mentioned (including output of both dry and wet deposition).
- Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass, and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
- Apply the appropriate scaling factors found in the IWAQM Phase II Report (Section 3.3, Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results were compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS). The results of the deposition analysis for each of the Class I areas are presented Table 5-6 and represent the highest impact occurring anywhere on the respective receptor rings for each Class I area. As illustrated in the table, the deposition results for both the ENP and the CWA are less than the 0.01 DAT and, as such, no further analysis is necessary.

Table 5-6
Deposition Results

Class I Area	Total Nitrogen Deposition[a] (kg/ha/yr)		Total Sulfur Deposition[b] (kg/ha/yr)		Deposition Analysis Threshold[c]
	NG	FO	NG	FO	
Chassahowitzka WA	2.3E-4	6.5E-4	3.7E-4	1.8E-4	0.01
Everglades NP	3.3E-4	9.7E-4	5.1E-4	2.6E-4	0.01

[a]Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
[b]Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
[c]For all areas east of the Mississippi River.

5.3.8.3 Class I Impact Analysis. Ground-level impacts (in $\mu g/m^3$) at the ENP and CWA were calculated for NO_x, SO_2, and PM/PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Table 5-7 presents the maximum results of the Class I analysis for the 5 year period that was modeled. As illustrated in the table, there are no impacts above the Class I SILs at either the ENP or the CWA and, as such, no further analysis is necessary.

Table 5-7
Class I Significant Impact Levels (SIL) Modeling Results

Pollutant	Averaging Period	Model-Predicted Impact[a] (μg/m³)		PSD Class I SIL[b] (μg/m³)	Exceed SIL?
		Natural Gas	Fuel Oil		
Chassahowitzka Wilderness Area					
NO_x	Annual	6.90E-5	3.15E-4	0.10	NO
SO_2	Annual	2.64E-4	1.21E-4	0.08	NO
	24 Hour	5.95E-3	2.56E-3	0.20	NO
	3 Hour	1.61E-2	7.15E-3	1.0	NO
PM/PM_{10}	Annual	1.04E-3	1.39E-3	0.16	NO
	24 Hour	2.70E-2	3.50E-2	0.32	NO
Everglades National Park					
NO_x	Annual	2.53E-4	1.12E-3	0.10	NO
SO_2	Annual	5.37E-4	2.42E-4	0.08	NO
	24 Hour	1.01E-2	4.41E-3	0.20	NO
	3 Hour	3.35E-2	1.46E-2	1.0	NO
PM/PM_{10}	Annual	1.92E-3	2.55E-3	0.16	NO
	24 Hour	4.05E-2	5.27E-2	0.32	NO

[a]Model-predicted impacts are for the 5 year period that was in the analysis: 1987, 1988, 1989, 1990, and 1991.
[b]Class I Significant Impact Levels are calculated as 4 percent of the PSD Class I Increment values.

Appendix A
Emission Calculation Spreadsheet

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Combustion Turbine Unit 1
GE PG7241 data
Prepared by: Black & Veatch

CT performance data at average ambient temperature (73°F) and 100% load
Calculations based on 12/15/04 performance runs. Natural gas sulfur content of 2 grains per 100 scf.
ULS fuel oil sulfur content of 0.0015 percent.

Operational restrictions:
natural gas firing 8760 hours per year
fuel oil firing 500 hours per year

	Combined Cycle Operation with Duct Burner and SCR								
	Natural Gas Fired		Fuel Oil Fired						
Pollutant	Hourly Emission Rate - Case 5a (lb/hour)	Potential to Emit (tpy)	Hourly Emission Rate - Case 6a (lb/hour)	Potential to Emit (tpy)	Potential to Emit on a Maximum Pollutant by Pollutant Basis (tpy)	PSD SEL (tpy)	PSD Major Modification (Yes/No)	Natural Gas Fired - Max Emission Rate (lb/hour)	Fuel Oil Fired - Max Emission Rate (lb/hour)
NO_x	16.5	72.3	76.0	19.0	87.1	40	Yes	17.5	81.1
CO	50.1	219.4	86.2	21.6	228.5	100	Yes	52.3	92.4
PM (front half)	14.5	63.5	22.5	5.6	65.5	25	Yes	14.7	22.5
PM_{10} (front half)	14.5	63.5	22.5	5.6	65.5	15	Yes	14.7	22.5
PM (front and back half)	38.0	166.4	49.9	12.5	169.4	25	Yes	38	52
PM_{10} (front and back half)	38.0	166.4	49.9	12.5	169.4	15	Yes	38	52
SO_2 [a]	12.9	56.5	6.04	1.5	56.5	40	Yes	13.6	6.3
VOC	5.0	21.9	9.7	2.4	23.1	40	No	5.1	10.2
H_2SO_4 mist [b]	5.12	22.4	1.95	0.5	22.4	7	Yes	6.06	3.49

[a] SO_2 emissions do not include the effect of SO_2 oxidation to SO_3.
[b] H_2SO_4 based on SO_2 to SO_3 oxidation effects and 100% of SO_3 is converted to H_2SO_4.

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Auxiliary Boiler
Prepared by: Black & Veatch

Operational restrictions:
Auxiliary boiler operation 8760 hours per year

Auxiliary Boiler Emissions		
Pollutant	Hourly Emission Rate (lb/hour)	Potential to Emit (tpy)
NO_x	0.260	1.14
CO	0.520	2.28
PM/PM_{10}	0.029	0.13
SO_2 [(a)]	0.040	0.18
VOC	0.040	0.18

[(a)] SO_2 emissions are calculated based on the boiler heat input rate of 7.2 mmBtu/hr, assuming a natural gas heating value of 1,020 mmBtu/mmscf and a natural gas sulfur content of 2 grains per 100 scf.

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Fire Pump Diesel Engine
Prepared by: Black & Veatch

Operational restrictions:
Fire pump diesel engine projected operation — 200 hours per year

Fire Pump Diesel Engine Emissions		
Pollutant	Hourly Emission Rate (lb/hour)	Potential to Emit (tpy)
NO_x	5.879	0.59
CO	1.225	0.12
PM/PM_{10}	0.113	0.01
SO_2	0.003	0.00
VOC	0.213	0.02

* Emission specs are for a Clarke Detroit Diesel - Allison Model DDFP-T6FA unit.

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Safe Shutdown Generator
Prepared by: Black & Veatch

Operational restrictions:
Safe Shutdown Generator
Projected Operation 200 hours per year

Safe Shutdown Generator Emissions		
Pollutant	Hourly Emission Rate (lb/hour)	Potential to Emit (tpy)
NO_x	11.253	1.13
CO	0.891	0.09
PM/PM_{10}	0.077	0.01
SO_2 [(a)]	0.008	0.00
VOC	0.110	0.01

* Emission specs are for a Caterpillar Engine
(a) SO_2 emission rates are based on a fuel consumption rate of 36.3 gal/hr (vendor information), a fuel density of 7.05 lb/gal (AP-42 Appendix A), and a fuel oil sulfur content of 0.0015 percent by weight.

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Cooling Tower PM_{10} Emissions
Prepared by: Black & Veatch

Cooling Tower Parameters

Given:

Circulating Flow Rate	111,130	gpm
Circulating Water TDS	3,918	ppm
Drift Percent	0.0005	%
Annual Operational Hours	8760	hrs

Requested:

Particle Size	10.0	microns

Calculated:

% Mass Less Than 10 microns	39.138	%
PM Emissions Rate	4.77	tpy
PM10 Emission Rate	1.87	tpy

EPRI Drift Spectrum

Droplet Size (um)	Droplet Volume (um3)	Droplet Mass (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Percent Smaller
10	5.24E+02	5.24E-04	9.32E-01	1.212	0.000
20	4.19E+03	4.19E-03	7.46E+00	2.424	0.196
30	1.41E+04	1.41E-02	2.52E+01	3.636	0.226
40	3.35E+04	3.35E-02	5.97E+01	4.848	0.514
50	6.54E+04	6.54E-02	1.17E+02	6.061	1.816
60	1.13E+05	1.13E-01	2.01E+02	7.273	5.702
70	1.80E+05	1.80E-01	3.20E+02	8.485	21.348
90	3.82E+05	3.82E-01	6.80E+02	10.909	49.812
110	6.97E+05	6.97E-01	1.24E+03	13.333	70.509
130	1.15E+06	1.15E+00	2.05E+03	15.758	82.023
150	1.77E+06	1.77E+00	3.15E+03	18.182	88.012
180	3.05E+06	3.05E+00	5.44E+03	21.818	91.032
210	4.85E+06	4.85E+00	8.64E+03	25.455	92.468
240	7.24E+06	7.24E+00	1.29E+04	29.091	94.091
270	1.03E+07	1.03E+01	1.84E+04	32.727	94.689
300	1.41E+07	1.41E+01	2.52E+04	36.364	96.288
350	2.24E+07	2.24E+01	4.00E+04	42.424	97.011
400	3.35E+07	3.35E+01	5.97E+04	48.485	98.340
450	4.77E+07	4.77E+01	8.50E+04	54.545	99.071
500	6.54E+07	6.54E+01	1.17E+05	60.606	99.071
600	1.13E+08	1.13E+02	2.01E+05	72.727	100.000

Source:
"Calculating Realistic PM10 Emissions from Cooling Towers." Joel Reisman and Gordon Frisbie. Abstract No. 216. Air & Waste Management Association 94th Annual Conference and Exhibition in Orlando, FL, June 25-28, 2001.

Interpolation to Find Required Value		
Given Values:	8.485	21.348
	10.909	49.812
Interpolated Value:	**10**	**39.138**

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Cooling Tower PM Emissions
Prepared by: Black & Veatch

Cooling Tower Parameters

Given:

Circulating Flow Rate	111,130	gpm
Circulating Water TDS	5,331	ppm
Drift Percent	0.0005	%
Annual Operational Hours	8760	hrs

Requested:

Particle Size	10.0	microns

Calculated:

% Mass Less Than 10 microns	27.683	%
PM Emissions Rate	6.49	tpy
PM10 Emission Rate	1.80	tpy

EPRI Drift Spectrum

Droplet Size (um)	Droplet Volume (um3)	Droplet Mass (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Percent Smaller
10	5.24E+02	5.24E-04	1.27E+00	1.343	0.000
20	4.19E+03	4.19E-03	1.02E+01	2.686	0.196
30	1.41E+04	1.41E-02	3.43E+01	4.029	0.226
40	3.35E+04	3.35E-02	8.12E+01	5.373	0.514
50	6.54E+04	6.54E-02	1.59E+02	6.716	1.816
60	1.13E+05	1.13E-01	2.74E+02	8.059	5.702
70	1.80E+05	1.80E-01	4.35E+02	9.402	21.348
90	3.82E+05	3.82E-01	9.25E+02	12.088	49.812
110	6.97E+05	6.97E-01	1.69E+03	14.775	70.509
130	1.15E+06	1.15E+00	2.79E+03	17.461	82.023
150	1.77E+06	1.77E+00	4.28E+03	20.147	88.012
180	3.05E+06	3.05E+00	7.40E+03	24.177	91.032
210	4.85E+06	4.85E+00	1.18E+04	28.206	92.468
240	7.24E+06	7.24E+00	1.75E+04	32.236	94.091
270	1.03E+07	1.03E+01	2.50E+04	36.265	94.689
300	1.41E+07	1.41E+01	3.43E+04	40.295	96.288
350	2.24E+07	2.24E+01	5.44E+04	47.011	97.011
400	3.35E+07	3.35E+01	8.12E+04	53.727	98.340
450	4.77E+07	4.77E+01	1.16E+05	60.442	99.071
500	6.54E+07	6.54E+01	1.59E+05	67.158	99.071
600	1.13E+08	1.13E+02	2.74E+05	80.590	100.000

Source:
"Calculating Realistic PM10 Emissions from Cooling Towers." Joel Reisman and Gordon Frisbie. Abstract No. 216. Air & Waste Management Association 94th Annual Conference and Exhibition in Orlando, FL, June 25-28, 2001.

Interpolation to Find Required Value		
Given Values:	9.402	21.348
	12.088	49.812
Interpolated Value:	**10**	**27.683**

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Potential to emit analysis
Diesel Fuel Storage Tank Emissions
Prepared by: Black & Veatch

BASED ON EPA TANKS PROGRAM

Average CT fuel oil use (lb/hr)	96540	From performance data
Fuel oil density (lb/gal)	7.05	From AP-42 Appendix A.
Annual fuel oil use (hr/yr)	500	Permitting basis
Annual tank throughput (gal/year)	6,846,809	
VOC emission rate from TANKS (tpy)	0.16	

Treasure Coast Energy Center
Combustion Turbine Unit 1 Project
138859
Potential to emit analysis
Total Project Emissions
Prepared by: Black & Veatch

Pollutant	Potential to Emit (tpy)	PSD SEL (tpy)	PSD Major Modification (Yes/No)
NO_x	90.0	40	YES
CO	231.0	100	YES
PM	176.1	25	YES
PM_{10}	171.4	15	YES
SO_2	56.6	40	YES
VOC*	23.4	40	NO
H_2SO_4 mist	22.4	7	YES

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Combustion Turbine Unit 1 - Distillate Oil Firing
GE PG7241 data
Prepared by: Black & Veatch

FUEL:	DISTILLATE OIL
HEAT INPUT (MMBtu/hr):	1881.5
HOURS OF OPERATION:	500
NUMBER OF TURBINES	1

DISTILLATE OIL FIRED TURBINE EMISSIONS

Pollutant	Emission factor[1] lb/MMBtu	Emissions lb/hr/turbine	Emissions tons/yr
1,3 Butadiene	1.60E-05	3.01E-02	0.008
Benzene	5.50E-05	1.03E-01	0.026
Formaldehyde	2.80E-04	5.27E-01	0.132
Naphthalene	3.50E-05	6.59E-02	0.016
PAH	4.00E-05	7.53E-02	0.019
		Total Organic HAP Emissions (tpy)	0.200

DISTILLATE OIL FIRED TURBINE METALLIC HAP EMISSIONS

Pollutant	Emission factor[2] lb/MMBtu	Emissions lb/hr/turbine	Emissions tons/yr
Arsenic	1.10E-05	2.07E-02	0.005
Beryllium	3.10E-07	5.83E-04	0.000
Cadmium	4.80E-06	9.03E-03	0.002
Chromium	1.10E-05	2.07E-02	0.005
Lead	1.40E-05	2.63E-02	0.007
Manganese	7.90E-04	1.49E+00	0.372
Mercury	1.20E-06	2.26E-03	0.001
Nickel	4.60E-06	8.65E-03	0.002
Selenium	2.50E-05	4.70E-02	0.012
		Total Metallic HAP Emissions (tpy)	0.405

[1] Emission factors from AP-42 Section 3.1 Table 3.1-4.
[2] Emission factors from AP-42 Section 3.1 Table 3.1-5.
Heat Input rate is at 100% load and average site ambient temperatures.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
1,3 Butadiene	0.008
Benzene	0.026
Formaldehyde	0.132
Naphthalene	0.016
PAH	0.019
Arsenic	0.005
Beryllium	0.000
Cadmium	0.002
Chromium	0.005
Lead	0.007
Manganese	0.372
Mercury	0.001
Nickel	0.002
Selenium	0.012
Total HAPs	0.606

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Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Combustion Turbine Unit 1 - Natural Gas Firing
GE PG7241 data
Prepared by: Black & Veatch

FUEL:		NATURAL GAS	
HEAT INPUT (MMBtu/hr):		1722.5	
HOURS OF OPERATION:		8760	
NUMBER OF TURBINES		1	
NATURAL GAS FIRED TURBINE ORGANIC HAP EMISSIONS			
Pollutant	**Emission factor[1] lb/MMBtu**	**Emissions lb/hr/turbine**	**Emissions tons/yr**
1,3 Butadiene	4.30E-07	7.41E-04	0.003
Acetaldehyde	4.00E-05	6.89E-02	0.302
Acrolein	6.40E-06	1.10E-02	0.048
Benzene	1.20E-05	2.07E-02	0.091
Ethylbenzene	3.20E-05	5.51E-02	0.241
Formaldehyde	7.10E-04	1.22E+00	5.357
Naphthalene	1.30E-06	2.24E-03	0.010
PAH	2.20E-06	3.79E-03	0.017
Propylene Oxide	2.90E-05	5.00E-02	0.219
Toluene	1.30E-04	2.24E-01	0.981
Xylenes	6.40E-05	1.10E-01	0.483
		Total Organic HAP Emissions (tpy)	7.751

[1] Emission factors from AP-42 Section 3.1 Table 3.1-3.
Heat Input rate is at 100% load and average site ambient temperatures.

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.003
Acetaldehyde	0.302
Acrolein	0.048
Benzene	0.091
Ethylbenzene	0.241
Formaldehyde	5.357
Naphthalene	0.010
PAH	0.017
Propylene Oxide	0.219
Toluene	0.981
Xylenes	0.483
Total HAPs	7.751

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Combustion Turbine Unit 1 - Totals
GE PG7241 data
Prepared by: Black & Veatch

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.011
Acetaldehyde	0.302
Acrolein	0.048
Benzene	0.111
Ethylbenzene	0.241
Formaldehyde	5.357
Naphthalene	0.026
PAH	0.034
Propylene Oxide	0.219
Toluene	0.981
Xylenes	0.483
Arsenic	0.005
Beryllium	0.000
Cadmium	0.002
Chromiuim	0.005
Lead	0.007
Manganese	0.372
Mercury	0.001
Nickel	0.002
Selenium	0.012
Total HAPs	7.914

Total for CT

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Combustion Turbine Unit 1 - Duct Burner
Prepared by: Black & Veatch

FUEL:	NATURAL GAS
HEAT INPUT (MMBtu/hr):	554.2
NATURAL GAS HEATING VALUE (MMBtu/MMscf):	1020
HOURS OF OPERATION:	8760
NUMBER OF DUCT BURNERS	1

NATURAL GAS COMBUSTION ORGANIC HAP EMISSIONS

Pollutant	Emission factor[1] lb/MMscf	Emissions lb/hr	Emissions tons/yr
2-Methylnaphthalene	2.40E-05	1.30E-05	5.712E-05
3-Methylchloranthrene	1.80E-06	9.78E-07	4.284E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05	8.69E-06	3.808E-05
Acenaphthene	1.80E-06	9.78E-07	4.284E-06
Acenaphthylene	1.80E-06	9.78E-07	4.284E-06
Anthracene	2.40E-06	1.30E-06	5.712E-06
Benz(a)anthracene	1.80E-06	9.78E-07	4.284E-06
Benzene	2.10E-03	1.14E-03	4.998E-03
Benzo(a)pyrene	1.20E-06	6.52E-07	2.856E-06
Benzo(b)fluoranthene	1.80E-06	9.78E-07	4.284E-06
Benzo(g,h,i)perylene	1.20E-06	6.52E-07	2.856E-06
Benzo(k)fluoranthene	1.80E-06	9.78E-07	4.284E-06
Chrysene	1.80E-06	9.78E-07	4.284E-06
Dibenzo(a,h)anthracene	1.20E-06	6.52E-07	2.856E-06
Dichlorobenzene	1.20E-03	6.52E-04	2.856E-03
Fluoranthene	3.00E-06	1.63E-06	7.139E-06
Fluorene	2.80E-06	1.52E-06	6.663E-06
Formaldehyde	7.50E-02	4.08E-02	1.785E-01
Hexane	1.80E+00	9.78E-01	4.284E+00
Indeno(1,2,3-cd)pyrene	1.80E-06	9.78E-07	4.284E-06
Naphthalene	6.10E-04	3.31E-04	1.452E-03
Phenanathrene	1.70E-05	9.24E-06	4.046E-05
Pyrene	5.00E-06	2.72E-06	1.190E-05
Toluene	3.40E-03	1.85E-03	8.091E-03
		Total Organic HAP Emissions (tpy)	4.480E+00

NATURAL GAS COMBUSTION METALLIC HAP EMISSIONS

Pollutant	Emission factor[2] lb/MMBtu	Emissions lb/hr/turbine	Emissions tons/yr
Arsenic	2.00E-04	1.09E-04	4.76E-04
Beryllium	1.20E-05	6.52E-06	2.86E-05
Cadmium	1.10E-03	5.98E-04	2.62E-03
Chromium	1.40E-03	7.61E-04	3.33E-03
Cobalt	8.40E-05	4.56E-05	2.00E-04
Manganese	3.80E-04	2.06E-04	9.04E-04
Mercury	2.60E-04	1.41E-04	6.19E-04
Nickel	2.10E-03	1.14E-03	5.00E-03
Selenium	2.40E-05	1.30E-05	5.71E-05
		Total Metallic HAP Emissions (tpy)	1.32E-02

(1) Emission factors from AP-42 Section 1.4 Table 1.4-3.
(2) Emission factors from AP-42 Section 1.4 Table 1.4-4.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
2-Methylnaphthalene	5.71E-05
3-Methylchloranthrene	4.28E-06
7,12-Dimethylbenz(a)anthracene	3.81E-05
Acenaphthene	4.28E-06
Acenaphthylene	4.28E-06
Anthracene	5.71E-06
Benz(a)anthracene	4.28E-06
Benzene	5.00E-03
Benzo(a)pyrene	2.86E-06
Benzo(b)fluoranthene	4.28E-06
Benzo(g,h,i)perylene	2.86E-06
Benzo(k)fluoranthene	4.28E-06
Chrysene	4.28E-06
Dibenzo(a,h)anthracene	2.86E-06
Dichlorobenzene	2.86E-03
Fluoranthene	7.14E-06
Fluorene	6.66E-06
Formaldehyde	1.78E-01
Hexane	4.28E+00
Indeno(1,2,3-cd)pyrene	4.28E-06
Naphthalene	1.45E-03
Phenanathrene	4.05E-05
Pyrene	1.19E-05
Toluene	8.09E-03
Arsenic	4.76E-04
Beryllium	2.86E-05
Cadmium	2.62E-03
Chromium	3.33E-03
Cobalt	2.00E-04
Manganese	9.04E-04
Mercury	6.19E-04
Nickel	5.00E-03
Selenium	5.71E-05
Total HAPs	4.49E+00

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Auxiliary Boiler
Prepared by: Black & Veatch

FUEL:	NATURAL GAS
HEAT INPUT (MMBtu/hr):	7.2
NATURAL GAS HEATING VALUE (MMBtu/MMscf):	1020
HOURS OF OPERATION:	8760
NUMBER OF BOILERS	1

NATURAL GAS COMBUSTION ORGANIC HAP EMISSIONS

Pollutant	Emission factor[1] lb/MMscf	Emissions lb/hr	Emissions tons/yr
2-Methylnaphthalene	2.40E-05	1.69E-07	7.42E-07
3-Methylchloranthrene	1.80E-06	1.27E-08	5.57E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.13E-07	4.95E-07
Acenaphthene	1.80E-06	1.27E-08	5.57E-08
Acenaphthylene	1.80E-06	1.27E-08	5.57E-08
Anthracene	2.40E-06	1.69E-08	7.42E-08
Benz(a)anthracene	1.80E-06	1.27E-08	5.57E-08
Benzene	2.10E-03	1.48E-05	6.49E-05
Benzo(a)pyrene	1.20E-06	8.47E-09	3.71E-08
Benzo(b)fluoranthene	1.80E-06	1.27E-08	5.57E-08
Benzo(g,h,i)perylene	1.20E-06	8.47E-09	3.71E-08
Benzo(k)fluoranthene	1.80E-06	1.27E-08	5.57E-08
Chrysene	1.80E-06	1.27E-08	5.57E-08
Dibenzo(a,h)anthracene	1.20E-06	8.47E-09	3.71E-08
Dichlorobenzene	1.20E-03	8.47E-06	3.71E-05
Fluoranthene	3.00E-06	2.12E-08	9.28E-08
Fluorene	2.80E-06	1.98E-08	8.66E-08
Formaldehyde	7.50E-02	5.29E-04	2.32E-03
Hexane	1.80E+00	1.27E-02	5.57E-02
Indeno(1,2,3-cd)pyrene	1.80E-06	1.27E-08	5.57E-08
Naphthalene	6.10E-04	4.31E-06	1.89E-05
Phenanathrene	1.70E-05	1.20E-07	5.26E-07
Pyrene	5.00E-06	3.53E-08	1.55E-07
Toluene	3.40E-03	2.40E-05	1.05E-04
		Total Organic HAP Emissions (tpy)	5.82E-02

NATURAL GAS COMBUSTION METALLIC HAP EMISSIONS

Pollutant	Emission factor[2] lb/MMBtu	Emissions lb/hr	Emissions tons/yr
Arsenic	2.00E-04	1.41E-06	6.18E-06
Beryllium	1.20E-05	8.47E-08	3.71E-07
Cadmium	1.10E-03	7.76E-06	3.40E-05
Chromium	1.40E-03	9.88E-06	4.33E-05
Cobalt	8.40E-05	5.93E-07	2.60E-06
Manganese	3.80E-04	2.68E-06	1.17E-05
Mercury	2.60E-04	1.84E-06	8.04E-06
Nickel	2.10E-03	1.48E-05	6.49E-05
Selenium	2.40E-05	1.69E-07	7.42E-07
		Total Metallic HAP Emissions (tpy)	1.72E-04

[1] Emission factors from AP-42 Section 1.4 Table 1.4-3.
[2] Emission factors from AP-42 Section 1.4 Table 1.4-4.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
2-Methylnaphthalene	7.42E-07
3-Methylchloranthrene	5.57E-08
7,12-Dimethylbenz(a)anthracene	4.95E-07
Acenaphthene	5.57E-08
Acenaphthylene	5.57E-08
Anthracene	7.42E-08
Benz(a)anthracene	5.57E-08
Benzene	6.49E-05
Benzo(a)pyrene	3.71E-08
Benzo(b)fluoranthene	5.57E-08
Benzo(g,h,i)perylene	3.71E-08
Benzo(k)fluoranthene	5.57E-08
Chrysene	5.57E-08
Dibenzo(a,h)anthracene	3.71E-08
Dichlorobenzene	3.71E-05
Fluoranthene	9.28E-08
Fluorene	8.66E-08
Formaldehyde	2.32E-03
Hexane	5.57E-02
Indeno(1,2,3-cd)pyrene	5.57E-08
Naphthalene	1.89E-05
Phenanathrene	5.26E-07
Pyrene	1.55E-07
Toluene	1.05E-04
Arsenic	6.18E-06
Beryllium	3.71E-07
Cadmium	3.40E-05
Chromium	4.33E-05
Cobalt	2.60E-06
Manganese	1.17E-05
Mercury	8.04E-06
Nickel	6.49E-05
Selenium	7.42E-07
Total HAPs	5.84E-02

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Diesel Engine Fire Pump
Prepared by: Black & Veatch

FUEL:	DISTILLATE OIL
HEAT INPUT (MMBtu/hr):	2.274
HOURS OF OPERATION:	200

DIESEL ENGINE ORGANIC HAP EMISSIONS

Pollutant	Emission factor[1] lb/MMBtu	Emissions lb/hr	Emissions tons/yr
1,3 Butadiene	3.91E-05	8.89E-05	0.000
Acetaldehyde	7.67E-04	1.74E-03	0.000
Acrolein	9.25E-05	2.10E-04	0.000
Benzene	9.33E-04	2.12E-03	0.000
Formaldehyde	1.18E-03	2.68E-03	0.000
Naphthalene	8.48E-05	1.93E-04	0.000
Toluene	4.09E-04	9.30E-04	0.000
Xylenes	2.85E-04	6.48E-04	0.000
PAH	1.68E-04	3.82E-04	0.000
		Total Organic HAP Emissions (tpy)	0.001

[1] Emission factors from AP-42 Section 3.3 Table 3.3-2.
Heat input rate is for a Clarke Detroit Diesel - Allison Model DDFP-T6FA unit.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
1,3 Butadiene	0.000
Acetaldehyde	0.000
Acrolein	0.000
Benzene	0.000
Formaldehyde	0.000
Naphthalene	0.000
Toluene	0.000
Xylenes	0.000
PAH	0.000
Total HAPs	0.001

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Safe Shutdown Generator
Prepared by: Black & Veatch

FUEL:	DISTILLATE OIL		
HEAT INPUT (MMBtu/hr):	5.08		
HOURS OF OPERATION:	200		
	DIESEL ENGINE ORGANIC HAP EMISSIONS		
Pollutant	**Emission factor[1] lb/MMBtu**	**Emissions lb/hr**	**Emissions tons/yr**
1,3 Butadiene	3.91E-05	1.99E-04	0.000
Acetaldehyde	7.67E-04	3.90E-03	0.000
Acrolein	9.25E-05	4.70E-04	0.000
Benzene	9.33E-04	4.74E-03	0.000
Formaldehyde	1.18E-03	5.99E-03	0.001
Naphthalene	8.48E-05	4.31E-04	0.000
Toluene	4.09E-04	2.08E-03	0.000
Xylenes	2.85E-04	1.45E-03	0.000
PAH	1.68E-04	8.53E-04	0.000
		Total Organic HAP Emissions (tpy)	0.002

[1] Emission factors from AP-42 Section 3.3 Table 3.3-2.
Heat input rate is for a Caterpillar Engine

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.000
Acetaldehyde	0.000
Acrolein	0.000
Benzene	0.000
Formaldehyde	0.001
Naphthalene	0.000
Toluene	0.000
Xylenes	0.000
PAH	0.000
Total HAPs	0.002

FMPA
Treasure Coast Energy Center
Combined Cycle Unit 1 Project
138859
Hazardous Air Pollutant (HAP) Emission Estimates
Totals
Prepared by: Black & Veatch

Summary of HAP Emissions	
Pollutant	Emissions[1] (tons per year)
1,3 Butadiene	0.011
2-Methylnaphthalene	0.000
3-Methylchloranthrene	0.000
7,12-Dimethylbenz(a)anthracene	0.000
Acenaphthene	0.000
Acenaphthylene	0.000
Acetaldehyde	0.302
Acrolein	0.048
Anthracene	0.000
Benz(a)anthracene	0.000
Benzene	0.117
Benzo(a)pyrene	0.000
Benzo(b)fluoranthene	0.000
Benzo(g,h,i)perylene	0.000
Benzo(k)fluoranthene	0.000
Chrysene	0.000
Dibenzo(a,h)anthracene	0.000
Dichlorobenzene	0.003
Ethylbenzene	0.241
Fluoranthene	0.000
Fluorene	0.000
Formaldehyde	5.538
Hexane	4.339
Indeno(1,2,3-cd)pyrene	0.000
Naphthalene	0.027
PAH	0.035
Phenanathrene	0.000
Propylene Oxide	0.219
Pyrene	0.000
Toluene	0.989
Xylenes	0.483
Arsenic	0.006
Beryllium	0.000
Cadmium	0.005
Chromiuim	0.009
Cobalt	0.000
Lead	0.007
Manganese	0.373
Mercury	0.001
Nickel	0.007
Selenium	0.012
Total HAPs[2]	12.468

[1] Maximum emissions for each pollutant are the worst case emission of that pollutant for combustion turbine operation plus the emissions from the duct burner and auxiliary equipment.

[2] Total HAP emissions are the maximum total HAP emissions from the combustion turbine (fuel oil firing) plus the total HAP emissions from the duct burner operation and auxiliary equipment.

Appendix B
Turbine Data

Owner FMPA
Plant Treasure Coast Energy Center
Project No. 138859
Title 1x1 Emissions Estimates

1/14/2005
FMPA
Treasure Coast Energy Center Unit 1
Black & Veatch Project 138859.0030
1x1 Emissions Estimates

Case Number	1	2	3	4	5	6	7
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Evap. Cooler
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	100	100	26	26	73	73	100
HRSG Duct Firing	Fired	Fired	Fired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Ambient Conditions							
Ambient Temperature, F	100.0	100.0	26.0	26.0	73.0	73.0	100.0
Ambient Relative Humidity, %	48.4	48.4	100.0	100.0	81.5	81.5	48.4
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance							
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	85	85	0	0	85	85	85
CTG Compressor Inlet Dry Bulb Temperature, F	85.2	85.2	26.0	26.0	69.5	69.5	85.2
CTG Compr. Inlet Relative Humidity, %	89.7	89.7	100.0	100.0	97.0	97.0	89.7
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	13.2	14.1	16.7	18.1	14.3	15.4	13.2
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	100%	100%	100%
Gross CTG Output, kW	154,500	163,400	183,500	191,000	163,800	173,200	154,500
Gross CTG Heat Rate, Btu/kWh (LHV)	9,650	10,310	9,220	10,050	9,480	10,200	9,650
Gross CTG Heat Rate, Btu/kWh (HHV)	10,705	10,980	10,228	10,704	10,516	10,863	10,705
CTG Heat Input, MBtu/h (LHV)	1,490.9	1,684.7	1,691.9	1,919.6	1,552.8	1,766.6	1,490.9
CTG Heat Input, MBtu/h (HHV)	1,653.9	1,794.2	1,876.8	2,044.4	1,722.5	1,881.5	1,653.9
CTG Water/Steam Injection Flow, lb/h	0	109,030	0	143,570	0	122,910	0
Injection Fluid/Fuel Ratio	0.0	1.2	0.0	1.4	0.0	1.3	0.0
CTG Exhaust Flow, lb/h	3,357,000	3,483,000	3,834,000	4,004,000	3,506,000	3,651,000	3,357,000
CTG Exhaust Temperature, F	1,148	1,135	1,082	1,060	1,129	1,113	1,148
Combustion Turbine Fuel							
Total CTG Fuel Flow, lb/h	71,620	92,060	81,280	104,890	74,600	96,540	71,620
CTG Fuel Temperature, F	365	60	365	60	365	60	365
CTG Fuel LHV, Btu/lb	20,816	18,300	20,816	18,300	20,816	18,300	20,816
CTG Fuel HHV, Btu/lb	23,091	19,490	23,091	19,490	23,091	19,490	23,091
HHV/LHV Ratio	1.1093	1.0650	1.1093	1.0650	1.1093	1.0650	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	85.00%	73.76%	85.00%	73.76%	85.00%	73.76%
H2	24.01%	14.80%	24.01%	14.80%	24.01%	14.80%	24.01%
N2	0.61%	0.20%	0.61%	0.20%	0.61%	0.20%	0.61%
O2	1.61%	0.00%	1.61%	0.00%	1.61%	0.00%	1.61%
S	0.00657%	0.00150%	0.00657%	0.00150%	0.00657%	0.00150%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Combustion Turbine Exhaust							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.91%	0.87%	0.94%	0.89%	0.92%	0.88%	0.91%
CO2	3.69%	5.24%	3.71%	5.24%	3.69%	5.26%	3.69%
H2O	10.71%	13.72%	7.65%	11.49%	9.46%	12.90%	10.71%
N2	72.44%	69.45%	74.85%	71.18%	73.42%	70.10%	72.44%
O2	12.25%	10.72%	12.86%	11.19%	12.50%	10.87%	12.25%
SO2, (after SO2 oxidation)	0.00010%	0.00003%	0.00010%	0.00003%	0.00010%	0.00003%	0.00010%
SO3, (after SO2 oxidation)	0.00002%	0.00001%	0.00002%	0.00001%	0.00002%	0.00001%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.13	28.01	28.47	28.26	28.27	28.11	28.13
Specific Volume, ft^3/lb	40.43	40.16	37.99	37.61	39.65	39.38	40.43
Specific Volume, scf/lb	13.49	13.54	13.33	13.43	13.42	13.50	13.49
Exhaust Gas Flow, acfm	2,262,059	2,332,449	2,427,561	2,509,841	2,316,882	2,396,273	2,262,059
Exhaust Gas Flow, scfm	754,766	785,997	851,787	896,229	784,175	821,475	754,766
CTG NOx Emissions (Without Post Combustion Emissions Control)							
Additonal Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	9.00	42.00	9.00	42.00	9.00	42.00	9.00
NOx, ppmvd (dry)	10.90	60.00	10.60	58.50	10.80	59.70	10.90
NOx, ppmvw (wet)	9.70	51.80	9.80	51.80	9.80	52.00	9.70
NOx, lb/h as NO2	55.0	300.0	62.0	342.0	57.0	315.0	55.0
NOx, lb/MBtu (LHV)	0.0369	0.1781	0.0366	0.1782	0.0367	0.1783	0.0369
NOx, lb/MBtu (HHV)	0.0333	0.1672	0.0330	0.1673	0.0331	0.1674	0.0333
CTG CO Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	7.40	14.00	7.60	14.40	7.50	14.10	7.40
CO, ppmvd (dry)	9.00	20.00	9.00	20.00	9.00	20.00	9.00
CO, ppmvw (wet)	8.00	17.30	8.30	17.70	8.10	17.40	8.00
CO, lb/h	27.0	60.1	31.4	70.3	28.3	64.0	27.0
CO, lb/MBtu (LHV)	0.0181	0.0357	0.0185	0.0366	0.0182	0.0362	0.0181
CO, lb/MBtu (HHV)	0.0163	0.0335	0.0167	0.0344	0.0164	0.0340	0.0163
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9083	0.2247	0.9083	0.2247	0.9083	0.2247	0.9083
SO2, ppmvd (dry)	1.1019	0.3212	1.0714	0.3130	1.0891	0.3194	1.1019
SO2, ppmvw (wet)	0.9839	0.2771	0.9894	0.2771	0.9861	0.2782	0.9839
SO2, lb/h	7.5216	2.2074	8.5362	2.5150	7.8346	2.3148	7.5216
SO2, lb/MBtu (LHV)	0.0050	0.0013	0.0050	0.0013	0.0050	0.0013	0.0050
SO2, lb/MBtu (HHV)	0.0045	0.0012	0.0045	0.0012	0.0045	0.0012	0.0045

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Case Number	1	2	3	4	5	6	7
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Evap. Cooler
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	100	100	26	26	73	73	100
HRSG Duct Firing	Fired	Fired	Fired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00

Combustion Turbine Exhaust - continued

	1	2	3	4	5	6	7
CTG UHC Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	6.5	5.7	6.4	5.7	6.4	5.7	6.5
UHC, ppmvd (dry)	7.8	8.1	7.6	7.9	7.7	8.0	7.8
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	13.4	14.0	15.1	16.0	14.0	15.0	13.4
UHC, lb/MBtu as CH4 (LHV)	0.0090	0.0083	0.0089	0.0083	0.0090	0.0085	0.0090
UHC, lb/MBtu as CH4 (HHV)	0.0081	0.0078	0.0081	0.0078	0.0081	0.0080	0.0081
CTG VOC Emissions (Without Post Combustion Emissions Control)							
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	20%	50%	20%	50%	20%	50%	20%
VOC, ppmvd (dry, 15% O2)	1.3	2.8	1.3	2.8	1.3	2.8	1.3
VOC, ppmvd (dry)	1.6	4.1	1.5	4.0	1.5	4.0	1.6
VOC, ppmvw (wet)	1.4	3.5	1.4	3.5	1.4	3.5	1.4
VOC, lb/h as CH4	2.7	7.0	3.0	8.0	2.8	7.5	2.7
VOC, lb/MBtu as CH4 (LHV)	0.0018	0.0042	0.0018	0.0042	0.0018	0.0042	0.0018
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0039	0.0016	0.0039	0.0016	0.0040	0.0016
CTG PM10 Emissions (without the Effects of SO2 Oxidation)							
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	17.0	9.0	17.0	9.0	17.0	9.0
PM10, lb/MBtu (LHV)	0.0060	0.0101	0.0053	0.0089	0.0058	0.0096	0.0060
PM10, lb/MBtu (HHV)	0.0054	0.0095	0.0048	0.0083	0.0052	0.0090	0.0054
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	18.0	34.0	18.0	34.0	18.0	34.0	18.0
PM10, lb/MBtu (LHV)	0.0121	0.0202	0.0106	0.0177	0.0116	0.0192	0.0121
PM10, lb/MBtu (HHV)	0.0109	0.0189	0.0096	0.0166	0.0104	0.0181	0.0109

HRSG Duct Burners

	1	2	3	4	5	6	7
Duct Burner Fuel							
Duct Burner Heat Input, MBtu/h (LHV)	499.6	499.6	471.3	498.3	491.7	499.6	0.0
Duct Burner Heat Input, MBtu/h (HHV)	554.2	554.2	522.8	552.8	545.4	554.2	0.0
Total Duct Burner Fuel Flow, lb/h	24,000	24,000	22,640	23,940	23,620	24,000	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions							
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	2.836	2.836	2.675	2.829	2.791	2.836	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.394	0.394	0.371	0.393	0.388	0.394	0.000
DB NOx, lb/h	44.30	44.30	41.80	44.20	43.60	44.30	0.00
DB CO, lb/h	22.20	22.20	20.90	22.10	21.80	22.20	0.00
DB UHC (as CH4), lb/h	33.30	33.30	31.40	33.20	32.70	33.30	0.00
DB VOC (as CH4), lb/h	2.20	2.20	2.10	2.20	2.20	2.20	0.00
DB PM10, lb/h (front half catch only)	5.50	5.50	5.20	5.50	5.50	5.50	0.00
DB PM10, lb/h (front and back half catch)	13.30	13.30	12.50	13.30	13.10	13.30	0.00

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Evap. Cooler
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	100	100	26	26	73	73	100
HRSG Duct Firing	Fired	Fired	Fired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Stack Emissions							
Stack Exhaust Analysis - Volume Basis - Wet							
Ar	0.90%	0.86%	0.93%	0.88%	0.91%	0.87%	0.91%
CO_2	4.86%	6.35%	4.69%	6.21%	4.81%	6.32%	3.69%
H_2O	12.95%	15.83%	9.55%	13.37%	11.59%	14.93%	10.71%
N_2	71.58%	68.65%	74.10%	70.47%	72.60%	69.33%	72.44%
O_2	9.71%	8.30%	10.73%	9.06%	10.09%	8.55%	12.25%
SO_2 (after SO_2 oxidation)	0.000120%	0.000060%	0.000120%	0.000050%	0.000120%	0.000060%	0.000090%
SO_3 (after SO_2 oxidation)	0.000040%	0.000020%	0.000040%	0.000010%	0.000040%	0.000020%	0.000040%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	168	250	167	252	168	251	184
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18
Stack Flow, lb/h	3,380,996	3,506,998	3,856,636	4,027,938	3,529,618	3,674,998	3,356,997
Stack Flow, scfm	763,543	795,505	860,031	904,944	792,988	830,550	754,766
Stack Flow, acfm	923,577	1,086,586	1,036,793	1,239,934	958,292	1,135,575	934,925
Stack Exit Velocity, ft/s	60.0	71.0	68.0	81.0	63.0	74.0	61.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	12.3	37.6	11.9	38.1	12.2	37.8	9.0
NOx, ppmvd (dry)	20.2	69.9	18.1	68.9	19.5	69.1	10.9
NOx, ppmvw (wet)	17.6	58.9	16.4	58.0	17.2	58.8	9.7
NOx, lb/h as NO_2 (includes correction adder)	99.3	344.3	103.8	386.2	100.6	359.3	55.0
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.0499	0.1578	0.0480	0.1597	0.0492	0.1586	0.0369
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.0450	0.1466	0.0433	0.1487	0.0444	0.1475	0.0333
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	2.0	8.0	2.0	8.0	2.0	8.0	2.0
NOx, ppmvd (dry)	3.3	14.9	3.0	14.1	3.2	14.6	2.4
NOx, ppmvw (wet)	2.9	12.5	2.8	12.2	2.8	12.4	2.2
NOx, lb/h as NO_2 (includes NOx margin applied to CTG)	18.1	73.2	17.5	81.1	16.5	76.0	12.2
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.0081	0.0335	0.0081	0.0336	0.0081	0.0336	0.0082
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.0073	0.0312	0.0073	0.0312	0.0073	0.0312	0.0074
SCR NH_3 slip, ppmvd (dry, 15% O_2)	10.0	5.0	10.0	5.0	10.0	5.0	10.0
SCR NH_3 slip, lb/h	29.4	16.8	31.9	18.6	30.2	17.4	22.0
Stack CO Emissions							
CO, ppmvd (dry, 15% O_2)	10.1	14.9	9.9	15.1	10.1	15.0	7.4
CO, ppmvd (dry)	16.6	27.7	15.2	26.6	16.1	27.3	9.0
CO, ppmvw (wet)	14.5	23.4	13.7	23.0	14.3	23.3	8.0
CO, lb/h (includes CO margin applied to CTG)	49.2	82.3	52.3	92.4	50.1	86.2	27.0
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0247	0.0377	0.0242	0.0382	0.0245	0.0380	0.0181
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0223	0.0350	0.0218	0.0356	0.0221	0.0354	0.0163
Stack SO_2 Emissions, after SO_2 Oxidation							
Assumed SO_2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO_2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO_2, ppmvd (dry, 15% O_2)	0.84	0.37	0.84	0.35	0.84	0.36	0.79
SO_2, ppmvd (dry)	1.38	0.69	1.27	0.62	1.34	0.67	0.96
SO_2, ppmvw (wet)	1.20	0.58	1.15	0.54	1.19	0.57	0.86
SO_2, lb/h	9.32	4.68	10.05	4.94	9.55	4.77	6.57
SO_2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0047	0.0021	0.0046	0.0020	0.0047	0.0021	0.0044
SO_2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0042	0.0020	0.0042	0.0019	0.0042	0.0020	0.0040

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CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Evap. Cooler
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	100	100	26	26	73	73	100
HRSG Duct Firing	Fired	Fired	Fired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Stack Emissions - continued							
Stack UHC Emissions							
UHC, ppmvd (dry, 15% O_2)	16.8	15.0	15.4	14.0	16.4	14.6	6.5
UHC, ppmvd	27.7	27.8	23.6	24.7	26.2	26.7	7.8
UHC, ppmvw	24.1	23.4	21.3	21.4	23.2	22.7	7.0
UHC, lb/h as CH_4 (includes correction adder)	46.7	47.3	46.5	49.2	46.7	48.3	13.4
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0234	0.0216	0.0215	0.0203	0.0229	0.0213	0.0090
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0211	0.0201	0.0194	0.0189	0.0206	0.0198	0.0081
Stack VOC Emissions							
VOC, ppmvd (dry, 15% O_2)	1.8	2.9	1.7	2.9	1.7	2.9	1.3
VOC, ppmvd (dry)	2.9	5.4	2.6	5.1	2.8	5.3	1.6
VOC, ppmvw (wet)	2.5	4.6	2.3	4.4	2.5	4.5	1.4
VOC, lb/h as CH_4 (Includes VOC correction as applied to CTG)	4.9	9.2	5.1	10.2	5.0	9.7	2.7
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0025	0.0042	0.0024	0.0042	0.0024	0.0043	0.0018
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0022	0.0039	0.0021	0.0039	0.0022	0.0040	0.0016
PM10 without the Effects of SO_2 oxidation							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	14.5	22.5	14.2	22.5	14.5	22.5	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0073	0.0103	0.0066	0.0093	0.0071	0.0099	0.0060
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0066	0.0096	0.0059	0.0087	0.0064	0.0093	0.0054
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	31.3	47.3	30.5	47.3	31.1	47.3	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0157	0.0217	0.0141	0.0195	0.0152	0.0209	0.0121
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0142	0.0201	0.0127	0.0182	0.0137	0.0194	0.0109
PM10 with the Effects of SO_2 Oxidation [Includes $(NH_4)_2$-(SO_4)]							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	14.5	22.5	14.2	22.5	14.5	22.5	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0073	0.0103	0.0066	0.0093	0.0071	0.0099	0.0060
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0066	0.0096	0.0059	0.0087	0.0064	0.0093	0.0054
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	38.0	49.8	38.0	50.0	38.0	49.9	23.8
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0191	0.0228	0.0176	0.0207	0.0186	0.0220	0.0160
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0172	0.0212	0.0158	0.0193	0.0168	0.0205	0.0144
Total Effects of SO_2 Oxidation							
Total SO_2 to SO_3 conversion rate, %vol	25.8%	20.9%	26.4%	21.4%	26.0%	21.1%	30.2%
Total Amount of SO_2 converted to SO_3, lb/h	3.24	1.23	3.60	1.35	3.35	1.27	2.84
Maximum Stack Ammonium Sulfate [$(NH_4)_2$-(SO_4)] (assuming 100% conversion from SO_3), lb/h	6.67	2.54	7.42	2.78	6.90	2.63	5.85
Maximum Stack H_2SO_4 (assuming 100% conversion from SO_3 to H_2SO_4), lb/h	4.95	1.89	5.50	2.06	5.12	1.95	4.34
Post Combustion Emissions Control Equipment							
Selective Catalytic Reduction (SCR)							
NO_x Removed in SCR, %wt	83.8%	78.8%	83.2%	79.0%	83.6%	78.8%	77.8%
NO_x removed in SCR, lb/h	83.2	271.2	86.4	305.1	84.1	283.3	42.8
Ammonia Slip, lb/h	29.4	16.8	31.9	18.6	30.2	17.4	22.0

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N_2 and 20.99% O_2
3. Standard conditions are defined as 60 F, 14.696 psia. Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH_4 calibration gas.
5. The CTG performance is from GTP, a General Electric estimation program.
6. The H_2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO_3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NO_x duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NO_x stack emissions to 2 and 8 ppmvd@15%O_2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

Owner FMPA
Plant Treasure Coast Energy Center
Project No. 138859
Title 1x1 Emissions Estimates

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Treasure Coast Energy Center Unit 1
Black & Veatch Project 138859.0030
1x1 Emissions Estimates

Case Number	8	9	10	11	12	13	14
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate
CTG Load	100%	100%	100%	100%	100%	75%	75%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off
CTG Steam/Water Injection	Water	No	Water	No	Water	No	Water
Ambient Temperature, F	100	26	26	73	73	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	566.31	2.00	566.31
Ambient Conditions							
Ambient Temperature, F	100.0	26.0	26.0	73.0	73.0	100.0	100.0
Ambient Relative Humidity, %	48.4	100.0	100.0	81.5	81.5	48.4	48.4
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance							
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	85	0	0	85	85	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	85.2	26.0	26.0	69.5	69.5	100.0	100.0
CTG Compr. Inlet Relative Humidity, %	89.7	100.0	100.0	97.0	97.0	48.5	48.5
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	14.1	16.7	18.1	14.3	15.4	8.6	9.3
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	100%	75%	75%
Gross CTG Output, kW	163,400	183,500	191,000	163,800	173,200	108,400	116,100
Gross CTG Heat Rate, Btu/kWh (LHV)	10,310	9,220	10,050	9,480	10,200	10,900	11,540
Gross CTG Heat Rate, Btu/kWh (HHV)	10,980	10,228	10,704	10,516	10,863	12,091	12,290
CTG Heat Input, MBtu/h (LHV)	1,684.7	1,691.9	1,919.6	1,552.8	1,766.6	1,181.6	1,339.8
CTG Heat Input, MBtu/h (HHV)	1,794.2	1,876.8	2,044.4	1,722.5	1,881.5	1,310.7	1,426.9
CTG Water/Steam Injection Flow, lb/h	109,030	0	143,570	0	122,910	0	80,680
Injection Fluid/Fuel Ratio	1.2	0.0	1.4	0.0	1.3	0.0	1.1
CTG Exhaust Flow, lb/h	3,483,000	3,834,000	4,004,000	3,506,000	3,651,000	2,688,000	2,785,000
CTG Exhaust Temperature, F	1,135	1,082	1,060	1,129	1,113	1,198	1,195
Combustion Turbine Fuel							
Total CTG Fuel Flow, lb/h	92,060	81,280	104,890	74,600	96,540	56,760	73,210
CTG Fuel Temperature, F	60	365	60	365	60	365	60
CTG Fuel LHV, Btu/lb	18,300	20,816	18,300	20,816	18,300	20,816	18,300
CTG Fuel HHV, Btu/lb	19,490	23,091	19,490	23,091	19,490	23,091	19,490
HHV/LHV Ratio	1.0650	1.1093	1.0650	1.1093	1.0650	1.1093	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	73.76%	85.00%	73.76%	85.00%	73.76%	85.00%
H2	14.80%	24.01%	14.80%	24.01%	14.80%	24.01%	14.80%
N2	0.20%	0.61%	0.20%	0.61%	0.20%	0.61%	0.20%
O2	0.00%	1.61%	0.00%	1.61%	0.00%	1.61%	0.00%
S	0.00150%	0.00657%	0.00150%	0.00657%	0.00150%	0.00657%	0.00150%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	566.31	2.00	566.31
Combustion Turbine Exhaust							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.87%	0.94%	0.89%	0.92%	0.88%	0.91%	0.88%
CO2	5.24%	3.71%	5.24%	3.69%	5.26%	3.66%	5.23%
H2O	13.72%	7.65%	11.49%	9.46%	12.90%	10.14%	12.88%
N2	69.45%	74.85%	71.18%	73.42%	70.10%	72.86%	70.10%
O2	10.72%	12.86%	11.19%	12.50%	10.87%	12.43%	10.91%
SO2, (after SO2 oxidation)	0.00003%	0.00010%	0.00003%	0.00010%	0.00003%	0.00010%	0.00003%
SO3, (after SO2 oxidation)	0.00001%	0.00002%	0.00001%	0.00002%	0.00001%	0.00002%	0.00001%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.01	28.47	28.26	28.27	28.11	28.19	28.10
Specific Volume, ft^3/lb	40.18	37.99	37.61	39.65	39.38	42.06	42.04
Specific Volume, scf/lb	13.54	13.33	13.43	13.42	13.50	13.46	13.50
Exhaust Gas Flow, acfm	2,332,449	2,427,561	2,509,841	2,316,882	2,396,273	1,884,288	1,951,357
Exhaust Gas Flow, scfm	785,997	851,787	896,229	784,175	821,475	603,008	626,625
CTG NOx Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	42.00	9.00	42.00	9.00	42.00	9.00	42.00
NOx, ppmvd (dry)	60.00	10.60	58.50	10.80	59.70	10.80	59.30
NOx, ppmvw (wet)	51.80	9.80	51.80	9.80	52.00	9.70	51.70
NOx, lb/h as NO2	300.0	62.0	342.0	57.0	315.0	43.0	236.0
NOx, lb/MBtu (LHV)	0.1781	0.0366	0.1782	0.0367	0.1783	0.0364	0.1761
NOx, lb/MBtu (HHV)	0.1672	0.0330	0.1673	0.0331	0.1674	0.0328	0.1654
CTG CO Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	14.00	7.60	14.40	7.50	14.10	7.50	14.20
CO, ppmvd (dry)	20.00	9.00	20.00	9.00	20.00	9.00	20.00
CO, ppmvw (wet)	17.30	8.30	17.70	8.10	17.40	8.10	17.40
CO, lb/h	60.1	31.4	70.3	28.3	64.0	22.0	49.0
CO, lb/MBtu (LHV)	0.0357	0.0185	0.0366	0.0182	0.0362	0.0186	0.0366
CO, lb/MBtu (HHV)	0.0335	0.0167	0.0344	0.0164	0.0340	0.0168	0.0343
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.2247	0.9083	0.2247	0.9083	0.2247	0.9083	0.2247
SO2, ppmvd (dry)	0.3212	1.0714	0.3130	1.0891	0.3194	1.0861	0.3174
SO2, ppmvw (wet)	0.2771	0.9894	0.2771	0.9861	0.2782	0.9759	0.2765
SO2, lb/h	2.2074	8.5362	2.5150	7.8346	2.3148	5.9610	1.7554
SO2, lb/MBtu (LHV)	0.0013	0.0050	0.0013	0.0050	0.0013	0.0050	0.0013
SO2, lb/MBtu (HHV)	0.0012	0.0045	0.0012	0.0045	0.0012	0.0045	0.0012

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Case Number	8	9	10	11	12	13	14
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate
CTG Load	100%	100%	100%	100%	100%	75%	75%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off
CTG Steam/Water Injection	Water	No	Water	No	Water	No	Water
Ambient Temperature, F	100	26	26	73	73	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	566.31	2.00	566.31
Combustion Turbine Exhaust - continued							
CTG UHC Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	5.7	6.4	5.7	6.4	5.7	6.5	5.7
UHC, ppmvd (dry)	8.1	7.6	7.9	7.7	8.0	7.8	8.0
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	14.0	15.1	16.0	14.0	15.0	11.0	11.1
UHC, lb/MBtu as CH4 (LHV)	0.0083	0.0089	0.0083	0.0090	0.0085	0.0093	0.0083
UHC, lb/MBtu as CH4 (HHV)	0.0078	0.0081	0.0078	0.0081	0.0080	0.0084	0.0078
CTG VOC Emissions (Without Post Combustion Emissions Control)							
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	50%	20%	50%	20%	50%	20%	50%
VOC, ppmvd (dry, 15% O2)	2.8	1.3	2.8	1.3	2.8	1.3	2.8
VOC, ppmvd (dry)	4.1	1.5	4.0	1.5	4.0	1.6	4.0
VOC, ppmvw (wet)	3.5	1.4	3.5	1.4	3.5	1.4	3.5
VOC, lb/h as CH4	7.0	3.0	8.0	2.8	7.5	2.2	5.6
VOC, lb/MBtu as CH4 (LHV)	0.0042	0.0018	0.0042	0.0018	0.0042	0.0019	0.0042
VOC, lb/MBtu as CH4 (HHV)	0.0039	0.0016	0.0039	0.0016	0.0040	0.0017	0.0039
CTG PM10 Emissions (without the Effects of SO2 Oxidation)							
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	*17.0*	*9.0*	*17.0*	*9.0*	*17.0*	*9.0*	*17.0*
PM10, lb/MBtu (LHV)	0.0101	0.0053	0.0089	0.0058	0.0096	0.0076	0.0127
PM10, lb/MBtu (HHV)	0.0095	0.0048	0.0083	0.0052	0.0090	0.0069	0.0119
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	34.0	18.0	34.0	18.0	34.0	18.0	34.0
PM10, lb/MBtu (LHV)	0.0202	0.0106	0.0177	0.0116	0.0192	0.0152	0.0254
PM10, lb/MBtu (HHV)	0.0189	0.0096	0.0166	0.0104	0.0181	0.0137	0.0238
HRSG Duct Burners							
Duct Burner Fuel							
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions							
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Case Number	8	9	10	11	12	13	14
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate
CTG Load	100%	100%	100%	100%	100%	75%	75%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off
CTG Steam/Water Injection	Water	No	Water	No	Water	No	Water
Ambient Temperature, F	100	26	26	73	73	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	566.31	2.00	566.31
Stack Emissions							
Stack Exhaust Analysis - Volume Basis - Wet							
Ar	0.87%	0.94%	0.89%	0.92%	0.88%	0.91%	0.88%
CO_2	5.24%	3.71%	5.24%	3.69%	5.26%	3.66%	5.23%
H_2O	13.72%	7.65%	11.49%	9.46%	12.90%	10.14%	12.88%
N_2	69.45%	74.85%	71.18%	73.42%	70.10%	72.86%	70.10%
O_2	10.72%	12.86%	11.19%	12.50%	10.87%	12.43%	10.91%
SO_2 (after SO_2 oxidation)	0.000020%	0.000090%	0.000020%	0.000090%	0.000020%	0.000090%	0.000020%
SO_3 (after SO_2 oxidation)	0.000010%	0.000040%	0.000010%	0.000040%	0.000010%	0.000040%	0.000010%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	268	179	263	182	265	173	250
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18
Stack Flow, lb/h	3,482,999	3,633,998	4,003,999	3,505,997	3,650,999	2,687,998	2,784,999
Stack Flow, scfm	785,997	851,787	896,229	784,175	821,475	603,008	626,625
Stack Flow, acfm	1,098,308	1,046,682	1,245,911	969,409	1,145,806	733,824	856,388
Stack Exit Velocity, ft/s	72.0	69.0	82.0	63.0	75.0	48.0	56.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	42.0	9.0	42.0	9.0	42.0	9.0	42.0
NOx, ppmvd (dry)	60.0	10.6	58.5	10.8	59.7	10.8	59.3
NOx, ppmvw (wet)	51.8	9.8	51.8	9.8	52.0	9.7	51.7
NOx, lb/h as NO_2 (includes correction adder)	300.0	62.0	342.0	57.0	315.0	43.0	236.0
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.1781	0.0366	0.1782	0.0367	0.1783	0.0364	0.1781
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.1672	0.0330	0.1673	0.0331	0.1674	0.0328	0.1654
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	8.0	2.0	8.0	2.0	8.0	2.0	8.0
NOx, ppmvd (dry)	11.4	2.4	11.1	2.4	11.4	2.4	11.3
NOx, ppmvw (wet)	9.9	2.2	9.9	2.2	9.9	2.1	9.8
NOx, lb/h as NO_2 (includes NOx margin applied to CTG)	57.1	13.8	65.1	12.7	60.0	9.6	45.0
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.0339	0.0081	0.0339	0.0082	0.0340	0.0081	0.0336
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.0318	0.0073	0.0319	0.0074	0.0319	0.0073	0.0315
SCR NH_3 slip, ppmvd (dry, 15% O_2)	5.0	10.0	5.0	10.0	5.0	10.0	5.0
SCR NH_3 slip, lb/h	13.1	25.0	14.9	22.9	13.7	17.4	10.4
Stack CO Emissions							
CO, ppmvd (dry, 15% O_2)	14.0	7.6	14.4	7.5	14.1	7.5	14.2
CO, ppmvd (dry)	20.0	9.0	20.0	9.0	20.0	9.0	20.0
CO, ppmvw (wet)	17.3	8.3	17.7	8.1	17.4	8.1	17.4
CO, lb/h (includes CO margin applied to CTG)	60.1	31.4	70.3	28.3	64.0	22.0	49.0
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0357	0.0185	0.0366	0.0182	0.0362	0.0186	0.0366
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0335	0.0167	0.0344	0.0164	0.0340	0.0168	0.0343
Stack SO_2 Emissions, after SO_2 Oxidation							
Assumed SO_2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO_2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO_2, ppmvd (dry, 15% O_2)	0.20	0.79	0.20	0.79	0.20	0.79	0.20
SO_2, ppmvd (dry)	0.28	0.94	0.27	0.95	0.28	0.95	0.28
SO_2, ppmvw (wet)	0.24	0.86	0.24	0.86	0.24	0.85	0.24
SO_2, lb/h	1.93	7.45	2.20	6.84	2.02	5.20	1.53
SO_2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0011	0.0044	0.0011	0.0044	0.0011	0.0044	0.0011
SO_2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0011	0.0040	0.0011	0.0040	0.0011	0.0040	0.0011

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Case Number	8	9	10	11	12	13	14
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate
CTG Load	100%	100%	100%	100%	100%	75%	75%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off
CTG Steam/Water Injection	Water	No	Water	No	Water	No	Water
Ambient Temperature, F	100	26	26	73	73	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	566.31	2.00	566.31
Stack Emissions - continued							
Stack UHC Emissions							
UHC, ppmvd (dry, 15% O2)	5.7	6.4	5.7	6.4	5.7	6.5	5.7
UHC, ppmvd	8.1	7.6	7.9	7.7	8.0	7.8	8.0
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4 (includes correction adder)	14.0	15.1	16.0	14.0	15.0	11.0	11.1
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0083	0.0089	0.0083	0.0090	0.0085	0.0093	0.0083
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0078	0.0081	0.0078	0.0081	0.0080	0.0084	0.0078
Stack VOC Emissions							
VOC, ppmvd (dry, 15% O2)	2.8	1.3	2.8	1.3	2.8	1.3	2.8
VOC, ppmvd (dry)	4.1	1.5	4.0	1.5	4.0	1.6	4.0
VOC, ppmvw (wet)	3.5	1.4	3.5	1.4	3.5	1.4	3.5
VOC, lb/h as CH4 (includes VOC correction as applied to CTG)	7.0	3.0	8.0	2.8	7.5	2.2	5.6
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0042	0.0018	0.0042	0.0018	0.0042	0.0019	0.0042
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0039	0.0016	0.0039	0.0016	0.0040	0.0017	0.0039
PM10 without the Effects of SO2 oxidation							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	17.0	9.0	17.0	9.0	17.0	9.0	17.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0101	0.0053	0.0089	0.0058	0.0096	0.0076	0.0127
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0095	0.0048	0.0083	0.0052	0.0090	0.0069	0.0119
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	34.0	18.0	34.0	18.0	34.0	18.0	34.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0202	0.0106	0.0177	0.0116	0.0192	0.0152	0.0254
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0189	0.0096	0.0166	0.0104	0.0181	0.0137	0.0238
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	17.0	9.0	17.0	9.0	17.0	9.0	17.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0101	0.0053	0.0089	0.0058	0.0096	0.0076	0.0127
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0095	0.0048	0.0083	0.0052	0.0090	0.0069	0.0119
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	35.7	24.6	36.0	24.1	35.8	22.6	35.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0212	0.0146	0.0187	0.0155	0.0203	0.0192	0.0264
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0199	0.0131	0.0176	0.0140	0.0190	0.0173	0.0248
Total Effects of SO2 Oxidation							
Total SO2 to SO3 conversion rate, %vol	30.2%	30.2%	30.2%	30.2%	30.2%	30.2%	30.2%
Total Amount of SO2 converted to SO3, lb/h	0.83	3.22	0.95	2.95	0.87	2.25	0.66
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	1.72	6.64	1.96	6.09	1.80	4.64	1.37
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	1.27	4.93	1.45	4.52	1.34	3.44	1.01

Post Combustion Emissions Control Equipment

	8	9	10	11	12	13	14
Selective Catalytic Reduction (SCR)							
NOx Removed in SCR, %wt	81.0%	77.8%	81.0%	77.8%	81.0%	77.8%	81.0%
NOx removed in SCR, lb/h	242.9	48.2	278.9	44.3	255.0	33.4	191.0
Ammonia Slip, lb/h	13.1	25.0	14.9	22.9	13.7	17.4	10.4

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from GTP, a General Electric estimation program.
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulatas. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	75%	75%	75%	75%	50%	50%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	26	26	73	73	100	100	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Ambient Conditions							
Ambient Temperature, F	26.0	26.0	73.0	73.0	100.0	100.0	26.0
Ambient Relative Humidity, %	100.0	100.0	81.5	81.5	48.4	48.4	100.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance							
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	26.0	26.0	73.0	73.0	100.0	100.0	26.0
CTG Compr. Inlet Relative Humidity, %	100.0	100.0	81.6	81.6	48.5	48.5	100.0
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	10.7	11.1	9.6	10.1	6.2	6.6	7.3
CTG Load Level (percent of Base Load)	75%	75%	75%	75%	50%	50%	50%
Gross CTG Output, kW	137,800	143,300	121,500	128,700	72,300	77,400	91,800
Gross CTG Heat Rate, Btu/kWh (LHV)	9,910	10,740	10,400	11,090	13,010	13,540	11,900
Gross CTG Heat Rate, Btu/kWh (HHV)	10,993	11,438	11,537	11,811	14,432	14,420	13,201
CTG Heat Input, MBtu/h (LHV)	1,363.6	1,539.0	1,263.6	1,427.3	940.6	1,048.0	1,092.4
CTG Heat Input, MBtu/h (HHV)	1,512.7	1,639.1	1,401.7	1,520.1	1,043.4	1,116.2	1,211.8
CTG Water/Steam Injection Flow, lb/h	0	106,600	0	91,020	0	54,570	0
Injection Fluid/Fuel Ratio	0.0	1.3	0.0	1.2	0.0	1.0	0.0
CTG Exhaust Flow, lb/h	3,027,000	3,093,000	2,843,000	2,916,000	2,277,000	2,341,000	2,478,000
CTG Exhaust Temperature, F	1,136	1,136	1,173	1,172	1,200	1,200	1,190
Combustion Turbine Fuel							
Total CTG Fuel Flow, lb/h	65,510	84,100	60,700	77,990	45,190	57,270	52,480
CTG Fuel Temperature, F	365	60	365	60	365	60	365
CTG Fuel LHV, Btu/lb	20,816	18,300	20,816	18,300	20,816	18,300	20,816
CTG Fuel HHV, Btu/lb	23,091	19,490	23,091	19,490	23,091	19,490	23,091
HHV/LHV Ratio	1.1093	1.0650	1.1093	1.0650	1.1093	1.0650	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	85.00%	73.76%	85.00%	73.76%	85.00%	73.76%
H2	24.01%	14.80%	24.01%	14.80%	24.01%	14.80%	24.01%
N2	0.61%	0.20%	0.61%	0.20%	0.61%	0.20%	0.61%
O2	1.61%	0.00%	1.61%	0.00%	1.61%	0.00%	1.61%
S	0.00657%	0.00150%	0.00657%	0.00150%	0.00657%	0.00150%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Combustion Turbine Exhaust							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.94%	0.89%	0.92%	0.88%	0.92%	0.89%	0.94%
CO2	3.78%	5.44%	3.71%	5.33%	3.44%	4.88%	3.70%
H2O	7.79%	11.49%	9.36%	12.49%	9.73%	11.68%	7.64%
N2	74.79%	71.27%	73.51%	70.44%	73.02%	70.89%	74.85%
O2	12.69%	10.90%	12.50%	10.85%	12.89%	11.65%	12.87%
SO2, (after SO2 oxidation)	0.00010%	0.00003%	0.00010%	0.00003%	0.00009%	0.00003%	0.00010%
SO3, (after SO2 oxidation)	0.00003%	0.00001%	0.00002%	0.00001%	0.00002%	0.00001%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.46	28.28	28.28	28.16	28.22	28.20	28.47
Specific Volume, ft^3/lb	39.90	40.12	41.19	41.30	42.31	42.30	41.58
Specific Volume, scf/lb	13.33	13.42	13.42	13.47	13.45	13.45	13.33
Exhaust Gas Flow, acfm	2,012,955	2,068,186	1,951,720	2,007,180	1,605,665	1,650,405	1,717,254
Exhaust Gas Flow, scfm	672,499	691,801	635,884	654,642	510,428	524,774	550,529
CTG NOx Emissions (Without Post Combustion Emissions Control)							
Additonal Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	9.00	42.00	9.00	42.00	9.00	42.00	9.00
NOx, ppmvd (dry)	10.90	60.80	10.80	60.20	10.10	54.70	10.60
NOx, ppmvw (wet)	10.00	53.80	9.80	52.70	9.10	48.30	9.80
NOx, lb/h as NO2	50.0	273.0	46.0	252.0	34.0	184.4	39.2
NOx, lb/MBtu (LHV)	0.0367	0.1774	0.0364	0.1766	0.0361	0.1759	0.0359
NOx, lb/MBtu (HHV)	0.0331	0.1666	0.0328	0.1658	0.0326	0.1652	0.0324
CTG CO Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	7.50	13.80	7.50	14.00	8.00	15.40	7.60
CO, ppmvd (dry)	9.00	20.00	9.00	20.00	9.00	20.00	9.00
CO, ppmvw (wet)	8.30	17.70	8.20	17.50	8.10	17.70	8.30
CO, lb/h	25.0	54.2	23.0	51.0	18.4	41.1	20.3
CO, lb/MBtu (LHV)	0.0183	0.0352	0.0182	0.0357	0.0195	0.0392	0.0186
CO, lb/MBtu (HHV)	0.0165	0.0331	0.0164	0.0336	0.0176	0.0368	0.0167
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9063	0.2247	0.9063	0.2247	0.9063	0.2247	0.9063
SO2, ppmvd (dry)	1.0951	0.3252	1.0922	0.3221	1.0170	0.2924	1.0702
SO2, ppmvw (wet)	1.0097	0.2878	0.9899	0.2819	0.9181	0.2582	0.9885
SO2, lb/h	6.8800	2.0165	6.3748	1.8700	4.7459	1.3732	5.5115
SO2, lb/MBtu (LHV)	0.0050	0.0013	0.0050	0.0013	0.0050	0.0013	0.0050
SO2, lb/MBtu (HHV)	0.0045	0.0012	0.0045	0.0012	0.0045	0.0012	0.0045

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Case Number	15	16	17	18	19	20	21
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	75%	75%	75%	75%	50%	50%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	26	26	73	73	100	100	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Combustion Turbine Exhaust - continued							
CTG UHC Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	6.3	5.5	6.4	5.6	6.9	6.1	6.4
UHC, ppmvd (dry)	7.6	7.9	7.7	8.0	7.8	7.9	7.6
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	12.0	12.3	11.3	12.0	9.1	9.3	10.0
UHC, lb/MBtu as CH4 (LHV)	0.0088	0.0080	0.0089	0.0084	0.0096	0.0089	0.0092
UHC, lb/MBtu as CH4 (HHV)	0.0079	0.0075	0.0081	0.0079	0.0087	0.0084	0.0083
CTG VOC Emissions (Without Post Combustion Emissions Control)							
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	20%	50%	20%	50%	20%	50%	20%
VOC, ppmvd (dry, 15% O2)	1.3	2.7	1.3	2.8	1.4	3.0	1.3
VOC, ppmvd (dry)	1.5	4.0	1.5	4.0	1.6	4.0	1.5
VOC, ppmvw (wet)	1.4	3.5	1.4	3.5	1.4	3.5	1.4
VOC, lb/h as CH4	2.4	6.1	2.3	6.0	1.8	4.7	2.0
VOC, lb/MBtu as CH4 (LHV)	0.0018	0.0040	0.0018	0.0042	0.0019	0.0044	0.0018
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0037	0.0016	0.0039	0.0017	0.0042	0.0017
CTG PM10 Emissions (without the Effects of SO2 Oxidation)							
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	17.0	9.0	17.0	9.0	17.0	9.0
PM10, lb/MBtu (LHV)	0.0066	0.0110	0.0071	0.0119	0.0096	0.0162	0.0082
PM10, lb/MBtu (HHV)	0.0059	0.0104	0.0064	0.0112	0.0086	0.0152	0.0074
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	18.0	34.0	18.0	34.0	18.0	34.0	18.0
PM10, lb/MBtu (LHV)	0.0132	0.0221	0.0142	0.0238	0.0191	0.0324	0.0165
PM10, lb/MBtu (HHV)	0.0119	0.0207	0.0128	0.0224	0.0173	0.0305	0.0149
HRSG Duct Burners							
Duct Burner Fuel							
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions							
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Case Number	15	16	17	18	19	20	21
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	75%	75%	75%	75%	50%	50%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	26	26	73	73	100	100	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00
Stack Emissions							
Stack Exhaust Analysis - Volume Basis - Wet							
Ar	0.94%	0.89%	0.92%	0.88%	0.92%	0.89%	0.94%
CO2	3.78%	5.44%	3.71%	5.33%	3.44%	4.88%	3.70%
H2O	7.79%	11.49%	9.36%	12.49%	9.73%	11.68%	7.64%
N2	74.79%	71.27%	73.51%	70.44%	73.02%	70.89%	74.85%
O2	12.69%	10.90%	12.50%	10.85%	12.89%	11.65%	12.87%
SO2 (after SO2 oxidation)	0.000090%	0.000030%	0.000090%	0.000020%	0.000080%	0.000020%	0.000090%
SO3 (after SO2 oxidation)	0.000040%	0.000010%	0.000040%	0.000010%	0.000030%	0.000010%	0.000040%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	167	247	172	248	167	243	158
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18
Stack Flow, lb/h	3,026,997	3,092,999	2,842,997	2,915,999	2,276,998	2,340,999	2,477,998
Stack Flow, acfm	672,499	691,801	635,884	654,642	510,428	524,774	550,529
Stack Flow, acfm	811,236	941,303	772,822	891,810	615,929	709,713	654,192
Stack Exit Velocity, ft/s	53.0	62.0	51.0	58.0	40.0	46.0	43.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O2)	9.0	42.0	9.0	42.0	9.0	42.0	9.0
NOx, ppmvd (dry)	10.9	60.8	10.8	60.2	10.1	54.7	10.6
NOx, ppmvw (wet)	10.0	53.8	9.8	52.7	9.1	48.3	9.8
NOx, lb/h as NO2 (includes correction adder)	50.0	273.0	46.0	252.0	34.0	184.4	39.2
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0367	0.1774	0.0364	0.1766	0.0361	0.1759	0.0359
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0331	0.1666	0.0328	0.1658	0.0326	0.1652	0.0324
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O2)	2.0	8.0	2.0	8.0	2.0	8.0	2.0
NOx, ppmvd (dry)	2.4	11.6	2.4	11.5	2.2	10.4	2.4
NOx, ppmvw (wet)	2.2	10.2	2.2	10.0	2.0	9.2	2.2
NOx, lb/h as NO2 (includes NOx margin applied to CTG)	11.1	52.0	10.2	48.0	7.6	35.1	8.7
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0081	0.0336	0.0081	0.0336	0.0080	0.0335	0.0080
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0073	0.0317	0.0073	0.0316	0.0072	0.0315	0.0072
SCR NH3 slip, ppmvd (dry, 15% O2)	10.0	5.0	10.0	5.0	10.0	5.0	10.0
SCR NH3 slip, lb/h	20.1	11.9	18.7	11.1	13.9	8.1	16.1
Stack CO Emissions							
CO, ppmvd (dry, 15% O2)	7.5	13.8	7.5	14.0	8.0	15.4	7.6
CO, ppmvd (dry)	9.0	20.0	9.0	20.0	9.0	20.0	9.0
CO, ppmvw (wet)	8.3	17.7	8.2	17.5	8.1	17.7	8.3
CO, lb/h (includes CO margin applied to CTG)	25.0	54.2	23.0	51.0	18.4	41.1	20.3
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0183	0.0352	0.0182	0.0357	0.0195	0.0392	0.0186
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0165	0.0331	0.0164	0.0336	0.0176	0.0368	0.0167
Stack SO2 Emissions, after SO2 Oxidation							
Assumed SO2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.79	0.20	0.79	0.20	0.79	0.20	0.79
SO2, ppmvd (dry)	0.96	0.28	0.95	0.28	0.89	0.26	0.93
SO2, ppmvw (wet)	0.88	0.25	0.86	0.25	0.80	0.23	0.86
SO2, lb/h	6.01	1.76	5.57	1.63	4.14	1.20	4.81
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0044	0.0011	0.0044	0.0011	0.0044	0.0011	0.0044
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0040	0.0011	0.0040	0.0011	0.0040	0.0011	0.0040

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Case Number	15	16	17	16	19	20	21
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas	Distillate	Natural Gas
CTG Load	75%	75%	75%	75%	50%	50%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	Water	No	Water	No	Water	No
Ambient Temperature, F	26	26	73	73	100	100	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	566.31	2.00	566.31	2.00	566.31	2.00

Stack Emissions - continued

	15	16	17	16	19	20	21
Stack UHC Emissions							
UHC, ppmvd (dry, 15% O2)	6.3	5.5	6.4	5.6	6.9	6.1	6.4
UHC, ppmvd	7.6	7.9	7.7	8.0	7.8	7.9	7.6
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4 (includes correction adder)	12.0	12.3	11.3	12.0	9.1	9.3	10.0
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0088	0.0080	0.0089	0.0084	0.0096	0.0089	0.0092
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0079	0.0075	0.0081	0.0079	0.0087	0.0084	0.0083
Stack VOC Emissions							
VOC, ppmvd (dry, 15% O2)	1.3	2.7	1.3	2.8	1.4	3.0	1.3
VOC, ppmvd (dry)	1.5	4.0	1.5	4.0	1.6	4.0	1.5
VOC, ppmvw (wet)	1.4	3.5	1.4	3.5	1.4	3.5	1.4
VOC, lb/h as CH4 (includes VOC correction as applied to CTG)	2.4	6.1	2.3	6.0	1.8	4.7	2.0
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0018	0.0040	0.0018	0.0042	0.0019	0.0044	0.0018
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0016	0.0037	0.0016	0.0039	0.0017	0.0042	0.0017
PM10 without the Effects of SO2 oxidation							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	17.0	9.0	17.0	9.0	17.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0066	0.0110	0.0071	0.0119	0.0096	0.0162	0.0082
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0059	0.0104	0.0064	0.0112	0.0086	0.0152	0.0074
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	18.0	34.0	18.0	34.0	18.0	34.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0132	0.0221	0.0142	0.0238	0.0191	0.0324	0.0165
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0119	0.0207	0.0128	0.0224	0.0173	0.0305	0.0149
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	17.0	9.0	17.0	9.0	17.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0066	0.0110	0.0071	0.0119	0.0096	0.0162	0.0082
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0059	0.0104	0.0064	0.0112	0.0086	0.0152	0.0074
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	23.4	35.6	23.0	35.5	21.7	35.1	22.3
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0171	0.0231	0.0182	0.0248	0.0231	0.0335	0.0204
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0154	0.0217	0.0164	0.0233	0.0208	0.0314	0.0184
Total Effects of SO2 Oxidation							
Total SO2 to SO3 conversion rate, %vol	30.2%	30.2%	30.2%	30.2%	30.2%	30.2%	30.2%
Total Amount of SO2 converted to SO3, lb/h	2.59	0.76	2.40	0.70	1.79	0.52	2.08
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	5.35	1.57	4.96	1.45	3.69	1.07	4.29
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	3.97	1.16	3.68	1.08	2.74	0.79	3.18

Post Combustion Emissions Control Equipment

	15	16	17	16	19	20	21
Selective Catalytic Reduction (SCR)							
NOx Removed in SCR, %wt	77.8%	81.0%	77.8%	81.0%	77.8%	81.0%	77.8%
NOx removed in SCR, lb/h	38.9	221.0	35.8	204.0	26.4	149.2	30.5
Ammonia Slip, lb/h	20.1	11.9	18.7	11.1	13.9	8.1	16.1

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia. Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The *CTG performance is from GTP, a General Electric estimation program.*
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

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Case Number	22	23	24	45	50	51	52
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	50%	50%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off
CTG Steam/Water Injection	Water	No	Water	No	No	No	No
Ambient Temperature, F	26	73	73	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	2.00	2.00	2.00
Ambient Conditions							
Ambient Temperature, F	26.0	73.0	73.0	100.0	59.0	59.0	59.0
Ambient Relative Humidity, %	100.0	81.5	81.5	48.4	60.0	60.0	60.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance							
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	85	85	0
CTG Compressor Inlet Dry Bulb Temperature, F	26.0	73.0	73.0	100.0	52.6	52.6	59.0
CTG Compr. Inlet Relative Humidity, %	100.0	81.6	81.6	48.5	92.9	92.9	60.2
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	7.5	6.7	7.0	12.3	15.3	15.3	15.0
CTG Load Level (percent of Base Load)	50%	50%	50%	100%	100%	100%	100%
Gross CTG Output, kW	95,500	81,000	85,800	144,600	172,200	172,200	169,000
Gross CTG Heat Rate, Btu/kWh (LHV)	12,710	12,450	13,090	9,835	9,355	9,355	9,390
Gross CTG Heat Rate, Btu/kWh (HHV)	13,536	13,811	13,941	10,910	10,377	10,377	10,416
CTG Heat Input, MBtu/h (LHV)	1,213.8	1,008.5	1,123.1	1,422.1	1,610.9	1,610.9	1,586.9
CTG Heat Input, MBtu/h (HHV)	1,292.7	1,118.7	1,196.2	1,577.6	1,787.0	1,787.0	1,760.3
CTG Water/Steam Injection Flow, lb/h	75,980	0	63,080	0	0	0	0
Injection Fluid/Fuel Ratio	1.2	0.0	1.0	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	2,514,000	2,363,000	2,418,000	3,235,000	3,646,000	3,646,000	3,602,000
CTG Exhaust Temperature, F	1,190	1,200	1,200	1,163	1,110	1,110	1,116
Combustion Turbine Fuel							
Total CTG Fuel Flow, lb/h	66,330	48,450	61,370	68,320	77,390	77,390	76,240
CTG Fuel Temperature, F	60	365	60	365	365	365	365
CTG Fuel LHV, Btu/lb	18,300	20,816	18,300	20,816	20,816	20,816	20,816
CTG Fuel HHV, Btu/lb	19,490	23,091	19,490	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.0650	1.1093	1.0650	1.1093	1.1093	1.1093	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	73.76%	85.00%	73.76%	73.76%	73.76%	73.76%
H2	14.80%	24.01%	14.80%	24.01%	24.01%	24.01%	24.01%
N2	0.20%	0.61%	0.20%	0.61%	0.61%	0.61%	0.61%
O2	0.00%	1.61%	0.00%	1.61%	1.61%	1.61%	1.61%
S	0.00150%	0.00657%	0.00150%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.90%	0.92%	0.89%	0.91%	0.93%	0.93%	0.93%
CO2	5.29%	3.56%	5.07%	3.66%	3.70%	3.70%	3.69%
H2O	10.69%	9.09%	11.45%	10.14%	8.38%	8.38%	8.15%
N2	71.83%	73.62%	71.15%	72.86%	74.27%	74.27%	74.45%
O2	11.28%	12.81%	11.43%	12.42%	12.72%	12.72%	12.78%
SO2, (after SO2 oxidation)	0.00003%	0.00010%	0.00003%	0.00010%	0.00010%	0.00010%	0.00010%
SO3, (after SO2 oxidation)	0.00001%	0.00002%	0.00001%	0.00002%	0.00002%	0.00002%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.35	28.30	28.24	28.19	28.39	28.39	28.41
Specific Volume, ft^3/lb	41.73	42.14	42.19	40.81	38.92	38.92	39.06
Specific Volume, scf/lb	13.38	13.41	13.43	13.46	13.37	13.37	13.35
Exhaust Gas Flow, acfm	1,748,487	1,659,614	1,700,257	2,200,339	2,365,039	2,365,039	2,344,902
Exhaust Gas Flow, scfm	560,622	528,131	541,229	725,718	812,450	812,450	801,445
CTG NOx Emissions (Without Post Combustion Emissions Control)							
Additonal Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	42.00	9.00	42.00	9.00	9.00	9.00	9.00
NOx, ppmvd (dry)	58.60	10.40	56.60	10.80	10.70	10.70	10.60
NOx, ppmvw (wet)	52.30	9.40	50.20	9.70	9.80	9.80	9.80
NOx, lb/h as NO2	213.5	36.2	197.6	52.0	59.0	59.0	58.0
NOx, lb/MBtu (LHV)	0.1759	0.0359	0.1759	0.0366	0.0366	0.0366	0.0365
NOx, lb/MBtu (HHV)	0.1652	0.0324	0.1652	0.0330	0.0330	0.0330	0.0329
CTG CO Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	14.30	7.80	14.80	7.50	7.60	7.60	7.60
CO, ppmvd (dry)	20.00	9.00	20.00	9.00	9.00	9.00	9.00
CO, ppmvw (wet)	17.90	8.20	17.70	8.10	8.20	8.20	8.30
CO, lb/h	45.0	19.1	43.0	26.0	30.0	30.0	29.4
CO, lb/MBtu (LHV)	0.0371	0.0190	0.0383	0.0183	0.0186	0.0186	0.0185
CO, lb/MBtu (HHV)	0.0348	0.0171	0.0359	0.0165	0.0168	0.0168	0.0167
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.2247	0.9063	0.2247	0.9063	0.9063	0.9063	0.9063
SO2, ppmvd (dry)	0.3135	1.0463	0.3030	1.0862	1.0782	1.0782	1.0734
SO2, ppmvw (wet)	0.2800	0.9512	0.2683	0.9760	0.9878	0.9878	0.9859
SO2, lb/h	1.5904	5.0683	1.4715	7.1751	8.1276	8.1276	8.0068
SO2, lb/MBtu (LHV)	0.0013	0.0050	0.0013	0.0050	0.0050	0.0050	0.0050
SO2, lb/MBtu (HHV)	0.0012	0.0045	0.0012	0.0045	0.0045	0.0045	0.0045

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Case Number	22	23	24	45	50	51	52
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	50%	50%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off
CTG Steam/Water Injection	Water	No	Water	No	No	No	No
Ambient Temperature, F	26	73	73	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust - continued							
CTG UHC Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	5.6	6.7	5.9	6.5	6.4	6.4	6.4
UHC, ppmvd (dry)	7.8	7.7	7.9	7.8	7.6	7.6	7.6
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	10.0	9.4	10.0	13.0	14.4	14.4	14.2
UHC, lb/MBtu as CH4 (LHV)	0.0082	0.0093	0.0089	0.0091	0.0090	0.0090	0.0090
UHC, lb/MBtu as CH4 (HHV)	0.0077	0.0084	0.0084	0.0082	0.0081	0.0081	0.0081
CTG VOC Emissions (Without Post Combustion Emissions Control)							
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	50%	20%	50%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	2.8	1.3	2.9	1.3	1.3	1.3	1.3
VOC, ppmvd (dry)	3.9	1.5	4.0	1.6	1.5	1.5	1.5
VOC, ppmvw (wet)	3.5	1.4	3.5	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	5.0	1.9	5.0	2.6	2.9	2.9	2.8
VOC, lb/MBtu as CH4 (LHV)	0.0041	0.0019	0.0045	0.0018	0.0018	0.0018	0.0018
VOC, lb/MBtu as CH4 (HHV)	0.0039	0.0017	0.0042	0.0016	0.0016	0.0016	0.0016
CTG PM10 Emissions (without the Effects of SO2 Oxidation)							
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	17.0	9.0	17.0	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0140	0.0089	0.0151	0.0063	0.0056	0.0056	0.0057
PM10, lb/MBtu (HHV)	0.0132	0.0080	0.0142	0.0057	0.0050	0.0050	0.0051
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	34.0	18.0	34.0	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0280	0.0178	0.0303	0.0127	0.0112	0.0112	0.0113
PM10, lb/MBtu (HHV)	0.0263	0.0161	0.0284	0.0114	0.0101	0.0101	0.0102
HRSG Duct Burners							
Duct Burner Fuel							
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	509.6	481.9	0.0	487.1
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	565.3	534.6	0.0	540.3
Total Duct Burner Fuel Flow, lb/h	0	0	0	24,480	23,150	0	23,400
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions							
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	2.892	2.735	0.000	2.765
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.402	0.380	0.000	0.384
DB NOx, lb/h	0.00	0.00	0.00	45.20	42.80	0.00	43.20
DB CO, lb/h	0.00	0.00	0.00	22.60	21.40	0.00	21.60
DB UHC (as CH4), lb/h	0.00	0.00	0.00	33.90	32.10	0.00	32.40
DB VOC (as CH4), lb/h	0.00	0.00	0.00	2.30	2.10	0.00	2.20
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	5.70	5.30	0.00	5.40
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	13.60	12.80	0.00	13.00

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	50%	50%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off
CTG Steam/Water Injection	Water	No	Water	No	No	No	No
Ambient Temperature, F	26	73	73	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	2.00	2.00	2.00
Stack Emissions							
Stack Exhaust Analysis - Volume Basis - Wet							
Ar	0.90%	0.92%	0.89%	0.90%	0.92%	0.93%	0.92%
CO_2	5.29%	3.56%	5.07%	4.90%	4.76%	3.70%	4.77%
H_2O	10.69%	9.09%	11.45%	12.52%	10.42%	8.38%	10.23%
N_2	71.63%	73.62%	71.15%	71.94%	73.47%	74.27%	73.63%
O_2	11.28%	12.81%	11.43%	9.73%	10.43%	12.72%	10.44%
SO_2 (after SO_2 oxidation)	0.000020%	0.000080%	0.000020%	0.000120%	0.000120%	0.000090%	0.000120%
SO_3 (after SO_2 oxidation)	0.000010%	0.000040%	0.000010%	0.000040%	0.000040%	0.000040%	0.000040%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	243	164	243	166	167	180	166
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18
Stack Flow, lb/h	2,513,999	2,362,998	2,417,999	3,259,476	3,669,146	3,645,997	3,625,396
Stack Flow, scfm	560,622	528,131	541,229	735,013	821,278	812,450	810,277
Stack Flow, acfm	758,809	634,072	732,251	885,492	990,671	1,000,827	976,441
Stack Exit Velocity, ft/s	50.0	42.0	48.0	58.0	65.0	66.0	64.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	42.0	9.0	42.0	12.5	12.0	9.0	12.1
NOx, ppmvd (dry)	58.6	10.4	58.6	20.6	18.8	10.7	18.9
NOx, ppmvw (wet)	52.3	9.4	50.2	18.0	16.8	9.8	17.0
NOx, lb/h as NO_2 (includes correction adder)	213.5	36.2	197.6	97.2	101.8	59.0	101.2
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.1759	0.0359	0.1759	0.0503	0.0486	0.0366	0.0488
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.1652	0.0324	0.1652	0.0454	0.0438	0.0330	0.0440
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O_2)	8.0	2.0	8.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	11.2	2.3	10.8	3.3	3.1	2.4	3.1
NOx, ppmvw (wet)	10.0	2.1	9.6	2.9	2.8	2.2	2.8
NOx, lb/h as NO_2 (includes NOx margin applied to CTG)	40.7	8.0	37.6	15.6	16.9	13.1	16.7
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.0335	0.0080	0.0335	0.0081	0.0081	0.0081	0.0081
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.0315	0.0072	0.0315	0.0073	0.0073	0.0073	0.0073
SCR NH_3 slip, ppmvd (dry, 15% O_2)	5.0	10.0	5.0	10.0	10.0	10.0	10.0
SCR NH_3 slip, lb/h	9.4	14.9	8.7	28.5	30.9	23.8	30.6
Stack CO Emissions							
CO, ppmvd (dry, 15% O_2)	14.3	7.8	14.8	10.4	10.0	7.6	10.1
CO, ppmvd (dry)	20.0	9.0	20.0	17.1	15.7	9.0	15.8
CO, ppmvw (wet)	17.9	8.2	17.7	14.9	14.0	8.2	14.2
CO, lb/h (includes CO margin applied to CTG)	45.0	19.1	43.0	48.6	51.4	30.0	51.0
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0371	0.0190	0.0383	0.0252	0.0246	0.0186	0.0246
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0348	0.0171	0.0359	0.0227	0.0221	0.0168	0.0222
Stack SO_2 Emissions, after SO_2 Oxidation							
Assumed SO_2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO_2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO_2, ppmvd (dry, 15% O_2)	0.20	0.79	0.20	0.85	0.84	0.79	0.84
SO_2, ppmvd (dry)	0.27	0.91	0.28	1.39	1.31	0.94	1.31
SO_2, ppmvw (wet)	0.24	0.83	0.23	1.22	1.17	0.86	1.18
SO_2, lb/h	1.39	4.44	1.28	9.07	9.75	7.10	9.67
SO_2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0011	0.0044	0.0011	0.0047	0.0047	0.0044	0.0047
SO_2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0011	0.0040	0.0011	0.0042	0.0042	0.0040	0.0042

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Natural Gas	Distillate	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	50%	50%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off
CTG Steam/Water Injection	Water	No	Water	No	No	No	No
Ambient Temperature, F	26	73	73	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	2.00	566.31	2.00	2.00	2.00	2.00
Stack Emissions - continued							
Stack UHC Emissions							
UHC, ppmvd (dry, 15% O2)	5.6	6.7	5.9	17.4	16.0	6.4	16.2
UHC, ppmvd	7.8	7.7	7.9	28.7	24.9	7.6	25.3
UHC, ppmvw	7.0	7.0	7.0	25.1	22.3	7.0	22.7
UHC, lb/h as CH4 (includes correction adder)	10.0	9.4	10.0	46.9	46.5	14.4	46.7
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0082	0.0093	0.0089	0.0243	0.0222	0.0090	0.0225
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0077	0.0084	0.0084	0.0219	0.0200	0.0081	0.0203
Stack VOC Emissions							
VOC, ppmvd (dry, 15% O2)	2.8	1.3	2.9	1.8	1.7	1.3	1.7
VOC, ppmvd (dry)	3.9	1.5	4.0	3.0	2.7	1.5	2.7
VOC, ppmvw (wet)	3.5	1.4	3.5	2.6	2.4	1.4	2.4
VOC, lb/h as CH4 (includes VOC correction as applied to CTG)	5.0	1.9	5.0	4.9	5.0	2.9	5.0
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0041	0.0019	0.0045	0.0025	0.0024	0.0018	0.0024
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0039	0.0017	0.0042	0.0023	0.0022	0.0016	0.0022
PM10 without the Effects of SO2 oxidation							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	17.0	9.0	17.0	14.7	14.3	9.0	14.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0140	0.0089	0.0151	0.0076	0.0069	0.0056	0.0069
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0132	0.0080	0.0142	0.0068	0.0062	0.0050	0.0063
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	34.0	18.0	34.0	31.6	30.8	18.0	31.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0280	0.0178	0.0303	0.0163	0.0147	0.0112	0.0149
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0263	0.0161	0.0284	0.0147	0.0133	0.0101	0.0135
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	17.0	9.0	17.0	14.7	14.3	9.0	14.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0140	0.0089	0.0151	0.0076	0.0069	0.0056	0.0069
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0132	0.0080	0.0142	0.0068	0.0062	0.0050	0.0063
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	35.2	22.0	35.1	38.0	37.9	24.3	38.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0290	0.0218	0.0313	0.0197	0.0181	0.0151	0.0183
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0273	0.0196	0.0294	0.0177	0.0163	0.0136	0.0165
Total Effects of SO2 Oxidation							
Total SO2 to SO3 conversion rate, %vol	30.2%	30.2%	30.2%	25.6%	26.1%	30.2%	26.1%
Total Amount of SO2 converted to SO3, lb/h	0.60	1.92	0.55	3.11	3.45	3.06	3.41
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	1.24	3.96	1.14	6.42	7.12	6.32	7.03
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	0.92	2.94	0.85	4.77	5.28	4.69	5.22
Post Combustion Emissions Control Equipment							
Selective Catalytic Reduction (SCR)							
NOx Removed in SCR, %wt	81.0%	77.8%	81.0%	84.0%	83.4%	77.8%	83.5%
NOx removed in SCR, lb/h	172.9	28.2	159.9	81.7	84.9	45.9	84.5
Ammonia Slip, lb/h	9.4	14.9	8.7	28.5	30.9	23.8	30.6

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from GTP, a General Electric estimation program.
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

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Case Number	53	54	55	56	57	58	59
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Evap. Cooler	Off	Evap. Cooler	Off
CTG Steam/Water Injection	No	No	No	No	Water	Water	Water
Ambient Temperature, F	59	59	59	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	566.31	566.31	566.31
Ambient Conditions							
Ambient Temperature, F	59.0	59.0	59.0	100.0	59.0	59.0	59.0
Ambient Relative Humidity, %	60.0	60.0	60.0	48.4	60.0	60.0	60.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance							
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	85	0	85	0
CTG Compressor Inlet Dry Bulb Temperature, F	59.0	59.0	59.0	85.2	59.0	52.6	59.0
CTG Compr. Inlet Relative Humidity, %	60.2	60.2	60.2	89.7	60.2	92.9	60.2
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	15.0	9.9	6.9	13.2	13.2	13.2	13.2
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	100%	100%	100%
Gross CTG Output, kW	169,000	126,800	84,500	154,500	179,600	182,000	179,600
Gross CTG Heat Rate, Btu/kWh (LHV)	9,390	10,230	12,270	9,650	10,150	10,120	10,150
Gross CTG Heat Rate, Btu/kWh (HHV)	10,416	11,348	13,611	10,705	10,810	10,778	10,810
CTG Heat Input, MBtu/h (LHV)	1,586.9	1,297.2	1,036.8	1,490.9	1,822.9	1,841.8	1,822.9
CTG Heat Input, MBtu/h (HHV)	1,760.3	1,438.9	1,150.1	1,653.9	1,941.4	1,961.6	1,941.4
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	135,980	135,030	135,980
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0	1.4	1.3	1.4
CTG Exhaust Flow, lb/h	3,602,000	2,904,000	2,403,000	3,357,000	3,763,000	3,806,000	3,763,000
CTG Exhaust Temperature, F	1,116	1,161	1,200	1,148	1,098	1,092	1,098
Combustion Turbine Fuel							
Total CTG Fuel Flow, lb/h	76,240	62,320	49,810	71,620	99,610	100,650	99,610
CTG Fuel Temperature, F	365	365	365	365	60	60	60
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	18,300	18,300	18,300
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	19,490	19,490	19,490
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	85.00%	85.00%	85.00%
H2	24.01%	24.01%	24.01%	24.01%	14.80%	14.80%	14.80%
N2	0.61%	0.61%	0.61%	0.61%	0.20%	0.20%	0.20%
O2	1.61%	1.61%	1.61%	1.61%	0.00%	0.00%	0.00%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00150%	0.00150%	0.00150%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	566.31	566.31	566.31
Combustion Turbine Exhaust							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.93%	0.93%	0.94%	0.91%	0.89%	0.89%	0.89%
CO2	3.69%	3.74%	3.62%	3.69%	5.28%	5.28%	5.28%
H2O	8.15%	8.25%	8.00%	10.71%	12.07%	12.17%	12.07%
N2	74.45%	74.41%	74.50%	72.44%	70.75%	70.67%	70.75%
O2	12.78%	12.67%	12.94%	12.25%	11.01%	11.00%	11.01%
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00003%	0.00003%	0.00003%
SO3, (after SO2 oxidation)	0.00002%	0.00002%	0.00002%	0.00002%	0.00001%	0.00001%	0.00001%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.41	28.41	28.42	28.13	28.20	28.19	28.20
Specific Volume, ft^3/lb	39.06	40.68	41.94	40.43	39.08	38.94	39.08
Specific Volume, scf/lb	13.35	13.36	13.35	13.49	13.45	13.46	13.45
Exhaust Gas Flow, acfm	2,344,902	1,968,912	1,679,697	2,262,059	2,450,967	2,470,094	2,450,967
Exhaust Gas Flow, scfm	801,445	646,624	534,668	754,766	843,539	853,813	843,539
CTG NOx Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	42.00	42.00	42.00
NOx, ppmvd (dry)	10.60	10.80	10.40	10.90	59.40	59.40	59.40
NOx, ppmvw (wet)	9.80	9.90	9.60	9.70	52.20	52.20	52.20
NOx, lb/h as NO2	58.0	47.0	37.2	55.0	322.1	325.5	322.1
NOx, lb/MBtu (LHV)	0.0365	0.0362	0.0359	0.0369	0.1767	0.1767	0.1767
NOx, lb/MBtu (HHV)	0.0329	0.0327	0.0324	0.0333	0.1659	0.1659	0.1659
CTG CO Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	7.60	7.50	7.80	7.40	14.10	14.10	14.10
CO, ppmvd (dry)	9.00	9.00	9.00	9.00	20.00	20.00	20.00
CO, ppmvw (wet)	8.30	8.30	8.30	8.00	17.60	17.60	17.60
CO, lb/h	29.4	24.0	20.0	27.0	65.9	66.6	65.9
CO, lb/MBtu (LHV)	0.0185	0.0185	0.0193	0.0181	0.0361	0.0361	0.0361
CO, lb/MBtu (HHV)	0.0167	0.0167	0.0174	0.0163	0.0339	0.0339	0.0339
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9083	0.9083	0.9083	0.9083	0.2247	0.2247	0.2247
SO2, ppmvd (dry)	1.0734	1.0892	1.0499	1.1019	0.3177	0.3177	0.3177
SO2, ppmvw (wet)	0.9859	0.9994	0.9658	0.9839	0.2794	0.2790	0.2794
SO2, lb/h	8.0068	6.5449	5.2311	7.5216	2.3884	2.4133	2.3884
SO2, lb/MBtu (LHV)	0.0050	0.0050	0.0050	0.0050	0.0013	0.0013	0.0013
SO2, lb/MBtu (HHV)	0.0045	0.0045	0.0045	0.0045	0.0012	0.0012	0.0012

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Case Number	53	54	55	56	57	58	59
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Evap. Cooler	Off	Evap. Cooler	Off
CTG Steam/Water Injection	No	No	No	No	Water	Water	Water
Ambient Temperature, F	59	59	59	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	566.31	566.31	566.31
Combustion Turbine Exhaust - continued							
CTG UHC Emissions (Without Post Combustion Emissions Control)							
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	6.4	6.4	6.6	6.5	5.6	5.6	5.6
UHC, ppmvd (dry)	7.6	7.6	7.6	7.8	8.0	8.0	8.0
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	14.2	11.5	9.5	13.4	15.0	15.2	15.0
UHC, lb/MBtu as CH4 (LHV)	0.0090	0.0089	0.0092	0.0090	0.0082	0.0082	0.0082
UHC, lb/MBtu as CH4 (HHV)	0.0081	0.0080	0.0083	0.0081	0.0077	0.0077	0.0077
CTG VOC Emissions (Without Post Combustion Emissions Control)							
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	20%	20%	20%	20%	50%	50%	50%
VOC, ppmvd (dry, 15% O2)	1.3	1.3	1.3	1.3	2.8	2.8	2.8
VOC, ppmvd (dry)	1.5	1.5	1.5	1.6	4.0	4.0	4.0
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	3.5	3.5	3.5
VOC, lb/h as CH4	2.8	2.3	1.9	2.7	7.5	7.6	7.5
VOC, lb/MBtu as CH4 (LHV)	0.0018	0.0018	0.0018	0.0018	0.0041	0.0041	0.0041
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0016	0.0017	0.0016	0.0039	0.0039	0.0039
CTG PM10 Emissions (without the Effects of SO2 Oxidation)							
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	9.0	9.0	9.0	17.0	17.0	17.0
PM10, lb/MBtu (LHV)	0.0057	0.0069	0.0087	0.0060	0.0093	0.0092	0.0093
PM10, lb/MBtu (HHV)	0.0051	0.0063	0.0078	0.0054	0.0088	0.0087	0.0088
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	18.0	18.0	18.0	18.0	34.0	34.0	34.0
PM10, lb/MBtu (LHV)	0.0113	0.0139	0.0174	0.0121	0.0187	0.0185	0.0187
PM10, lb/MBtu (HHV)	0.0102	0.0125	0.0157	0.0109	0.0175	0.0173	0.0175
HRSG Duct Burners							
Duct Burner Fuel							
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	499.6	498.5	499.6	0.0
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	554.2	553.0	554.2	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	24,000	23,950	24,000	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions							
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	2.836	2.830	2.836	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.394	0.393	0.394	0.000
DB NOx, lb/h	0.00	0.00	0.00	44.30	44.20	44.30	0.00
DB CO, lb/h	0.00	0.00	0.00	22.20	22.10	22.20	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	33.30	33.20	33.30	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	2.20	2.20	2.20	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	5.50	5.50	5.50	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	13.30	13.30	13.30	0.00

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CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Evap. Cooler	Off	Evap. Cooler	Off
CTG Steam/Water Injection	No	No	No	No	Water	Water	Water
Ambient Temperature, F	59	59	59	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	566.31	566.31	566.31
Stack Emissions							
Stack Exhaust Analysis - Volume Basis - Wet							
Ar	0.93%	0.93%	0.94%	0.90%	0.88%	0.88%	0.89%
CO2	3.69%	3.74%	3.62%	4.86%	6.32%	6.30%	5.28%
H2O	8.15%	8.25%	8.00%	12.95%	14.06%	14.14%	12.07%
N2	74.45%	74.41%	74.50%	71.58%	70.00%	69.92%	70.75%
O2	12.78%	12.67%	12.94%	9.71%	8.75%	8.76%	11.01%
SO2 (after SO2 oxidation)	0.000090%	0.000090%	0.000080%	0.000120%	0.000040%	0.000040%	0.000020%
SO3 (after SO2 oxidation)	0.000040%	0.000040%	0.000040%	0.000040%	0.000030%	0.000030%	0.000020%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	180	169	161	169	251	251	262
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18
Stack Flow, lb/h	3,601,997	2,903,997	2,402,998	3,380,996	3,786,948	3,829,996	3,762,999
Stack Flow, scfm	801,445	646,624	534,668	763,543	852,695	863,027	843,539
Stack Flow, acfm	986,348	782,144	638,397	924,140	1,167,012	1,180,917	1,172,175
Stack Exit Velocity, ft/s	65.0	51.0	42.0	61.0	76.0	77.0	77.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O2)	9.0	9.0	9.0	12.3	37.9	37.9	42.0
NOx, ppmvd (dry)	10.6	10.8	10.4	20.2	68.4	68.3	59.4
NOx, ppmvw (wet)	9.8	9.9	9.6	17.6	58.8	58.7	52.2
NOx, lb/h as NO2 (includes correction adder)	58.0	47.0	37.2	99.3	366.4	369.8	322.1
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0365	0.0362	0.0359	0.0499	0.1578	0.1579	0.1767
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0329	0.0327	0.0324	0.0450	0.1469	0.1470	0.1659
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)							
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	8.0	8.0	8.0
NOx, ppmvd (dry)	2.4	2.4	2.3	3.3	14.4	14.4	11.3
NOx, ppmvw (wet)	2.2	2.2	2.1	2.9	12.4	12.4	9.9
NOx, lb/h as NO2 (includes NOx margin applied to CTG)	12.9	10.4	8.3	16.1	77.3	78.0	61.4
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0081	0.0081	0.0080	0.0081	0.0333	0.0333	0.0337
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0073	0.0073	0.0072	0.0073	0.0310	0.0310	0.0316
SCR NH3 slip, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	23.4	19.2	15.3	29.4	17.8	18.0	14.1
Stack CO Emissions							
CO, ppmvd (dry, 15% O2)	7.6	7.5	7.8	10.1	15.0	15.0	14.1
CO, ppmvd (dry)	9.0	9.0	9.0	16.6	27.1	27.0	20.0
CO, ppmvw (wet)	8.3	8.3	8.3	14.5	23.3	23.2	17.6
CO, lb/h (includes CO margin applied to CTG)	29.4	24.0	20.0	49.2	88.0	88.7	65.9
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0185	0.0193	0.0247	0.0379	0.0379	0.0361
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0167	0.0167	0.0174	0.0223	0.0353	0.0353	0.0339
Stack SO2 Emissions, after SO2 Oxidation							
Assumed SO2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%	20.0%	20.0%	20.0%
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.79	0.79	0.79	0.84	0.29	0.29	0.16
SO2, ppmvd (dry)	0.94	0.95	0.92	1.38	0.52	0.52	0.22
SO2, ppmvw (wet)	0.86	0.87	0.84	1.20	0.45	0.44	0.20
SO2, lb/h	6.99	5.71	4.57	9.32	3.86	3.89	1.67
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0044	0.0044	0.0044	0.0047	0.0017	0.0017	0.0009
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0040	0.0040	0.0040	0.0042	0.0015	0.0015	0.0009

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Case Number	53	54	55	56	57	58	59
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%	100%
CTG Inlet Air Cooling	Off	Off	Off	Evap. Cooler	Off	Evap. Cooler	Off
CTG Steam/Water Injection	No	No	No	No	Water	Water	Water
Ambient Temperature, F	59	59	59	100	59	59	59
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Fired	Fired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	566.31	566.31	566.31
Stack Emissions - continued							
Stack UHC Emissions							
UHC, ppmvd (dry, 15% O2)	6.4	6.4	6.6	16.8	14.4	14.3	5.6
UHC, ppmvd	7.6	7.6	7.6	27.7	25.9	25.8	8.0
UHC, ppmvw	7.0	7.0	7.0	24.1	22.3	22.1	7.0
UHC, lb/h as CH4 (includes correction adder)	14.2	11.5	9.5	46.7	48.2	48.4	15.0
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0090	0.0089	0.0092	0.0234	0.0207	0.0207	0.0082
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0081	0.0080	0.0083	0.0211	0.0193	0.0192	0.0077
Stack VOC Emissions							
VOC, ppmvd (dry, 15% O2)	1.3	1.3	1.3	1.8	2.9	2.9	2.8
VOC, ppmvd (dry)	1.5	1.5	1.5	2.9	5.2	5.2	4.0
VOC, ppmvw (wet)	1.4	1.4	1.4	2.5	4.5	4.5	3.5
VOC, lb/h as CH4 (includes VOC correction as applied to CTG)	2.8	2.3	1.9	4.9	9.7	9.8	7.5
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0018	0.0018	0.0018	0.0025	0.0042	0.0042	0.0041
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0016	0.0016	0.0017	0.0022	0.0039	0.0039	0.0039
PM10 without the Effects of SO2 oxidation							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	9.0	9.0	14.5	22.5	22.5	17.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0057	0.0069	0.0087	0.0073	0.0097	0.0096	0.0093
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0051	0.0063	0.0078	0.0066	0.0090	0.0090	0.0088
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	18.0	18.0	18.0	31.3	47.3	47.3	34.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0113	0.0139	0.0174	0.0157	0.0204	0.0202	0.0187
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0102	0.0125	0.0157	0.0142	0.0190	0.0188	0.0175
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]							
PM10 Emissions - Front Half Catch Only							
PM10, lb/h	9.0	9.0	9.0	14.5	22.5	22.5	17.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0057	0.0069	0.0087	0.0073	0.0097	0.0096	0.0093
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0051	0.0063	0.0078	0.0066	0.0090	0.0090	0.0088
PM10 Emissions - Front and Back Half Catch							
PM10, lb/h	24.2	23.1	22.1	38.0	51.9	52.0	36.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0153	0.0178	0.0213	0.0191	0.0224	0.0222	0.0201
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0138	0.0160	0.0192	0.0172	0.0208	0.0207	0.0189
Total Effects of SO2 Oxidation							
Total SO2 to SO3 conversion rate, %vol	30.2%	30.2%	30.2%	25.8%	37.0%	37.0%	44.1%
Total Amount of SO2 converted to SO3, lb/h	3.02	2.47	1.97	3.24	2.27	2.28	1.32
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	6.23	5.09	4.07	6.67	4.67	4.71	2.72
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	4.62	3.78	3.02	4.95	3.47	3.49	2.02
Post Combustion Emissions Control Equipment							
Selective Catalytic Reduction (SCR)							
NOx Removed in SCR, %wt	77.8%	77.8%	77.8%	83.8%	78.9%	78.9%	81.0%
NOx removed in SCR, lb/h	45.1	36.6	29.0	83.2	289.1	291.8	260.8
Ammonia Slip, lb/h	23.4	19.2	15.3	29.4	17.8	18.0	14.1

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from GTP, a General Electric estimation program.
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Natural Gas	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	No	Water	Water
Ambient Temperature, F	59	59	59	100	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	566.31	566.31	2.00	566.31	566.31
Ambient Conditions						
Ambient Temperature, F	59.0	59.0	59.0	100.0	100.0	100.0
Ambient Relative Humidity, %	60.0	60.0	60.0	48.4	48.4	48.4
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance						
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	85	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	52.6	59.0	59.0	100.0	100.0	100.0
CTG Compr. Inlet Relative Humidity, %	92.9	60.2	60.2	48.5	48.5	48.5
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	13.2	13.2	13.2	13.2	13.2	13.2
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	100%	100%
Gross CTG Output, kW	182,000	134,700	89,800	144,600	154,800	154,800
Gross CTG Heat Rate, Btu/kWh (LHV)	10,120	10,980	12,960	9,835	10,480	10,480
Gross CTG Heat Rate, Btu/kWh (HHV)	10,778	11,694	13,802	10,910	11,161	11,161
CTG Heat Input, MBtu/h (LHV)	1,841.8	1,479.0	1,163.8	1,422.1	1,622.3	1,622.3
CTG Heat Input, MBtu/h (HHV)	1,961.6	1,575.2	1,239.5	1,577.5	1,727.8	1,727.8
CTG Water/Steam Injection Flow, lb/h	135,030	100,920	71,150	0	108,580	108,580
Injection Fluid/Fuel Ratio	1.3	1.3	1.1	0.0	1.2	1.2
CTG Exhaust Flow, lb/h	3,806,000	2,992,000	2,458,000	3,235,000	3,359,000	3,359,000
CTG Exhaust Temperature, F	1,092	1,159	1,200	1,163	1,151	1,151
Combustion Turbine Fuel						
Total CTG Fuel Flow, lb/h	100,650	80,820	63,600	68,320	88,650	88,650
CTG Fuel Temperature, F	60	60	60	365	60	60
CTG Fuel LHV, Btu/lb	18,300	18,300	18,300	20,816	18,300	18,300
CTG Fuel HHV, Btu/lb	19,490	19,480	19,490	23,091	19,490	19,490
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.1093	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	73.76%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	24.01%	14.80%	14.80%
N2	0.20%	0.20%	0.20%	0.61%	0.20%	0.20%
O2	0.00%	0.00%	0.00%	1.61%	0.00%	0.00%
S	0.00150%	0.00150%	0.00150%	0.00657%	0.00150%	0.00150%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	566.31	566.31	2.00	566.31	566.31
Combustion Turbine Exhaust						
CTG Exhaust Analysis (Volume Basis - Wet)						
Ar	0.89%	0.89%	0.90%	0.91%	0.88%	0.88%
CO2	5.28%	5.40%	5.19%	3.66%	5.24%	5.24%
H2O	12.17%	11.63%	10.88%	10.14%	13.39%	13.39%
N2	70.67%	70.99%	71.64%	72.86%	69.71%	69.71%
O2	11.00%	10.90%	11.39%	12.42%	10.79%	10.79%
SO2, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00010%	0.00003%	0.00003%
SO3, (after SO2 oxidation)	0.00001%	0.00001%	0.00001%	0.00002%	0.00001%	0.00001%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.19	28.24	28.32	28.19	28.05	28.05
Specific Volume, ft^3/lb	38.94	40.55	41.46	40.72	40.62	40.62
Specific Volume, scf/lb	13.46	13.44	13.40	13.46	13.53	13.53
Exhaust Gas Flow, acfm	2,470,094	2,022,093	1,698,478	2,195,487	2,274,043	2,274,043
Exhaust Gas Flow, scfm	853,813	670,208	548,953	725,718	757,455	757,455
CTG NOx Emissions (Without Post Combustion Emissions Control)						
Additonal Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	42.00	42.00	42.00	9.00	42.00	42.00
NOx, ppmvd (dry)	59.40	60.50	57.50	10.80	59.80	59.80
NOx, ppmvw (wet)	52.20	53.40	51.30	9.70	51.80	51.80
NOx, lb/h as NO2	325.5	261.6	206.2	52.5	286.9	286.9
NOx, lb/MBtu (LHV)	0.1767	0.1769	0.1772	0.0369	0.1768	0.1768
NOx, lb/MBtu (HHV)	0.1659	0.1661	0.1664	0.0333	0.1660	0.1660
CTG CO Emissions (Without Post Combustion Emissions Control)						
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	14.10	13.90	14.60	7.50	14.00	14.00
CO, ppmvd (dry)	20.00	20.00	20.00	9.00	20.00	20.00
CO, ppmvw (wet)	17.60	17.60	17.80	8.10	17.30	17.30
CO, lb/h	66.6	52.5	43.5	26.1	58.2	58.2
CO, lb/MBtu (LHV)	0.0361	0.0355	0.0374	0.0184	0.0359	0.0359
CO, lb/MBtu (HHV)	0.0339	0.0333	0.0351	0.0166	0.0337	0.0337
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)						
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.2247	0.2247	0.2247	0.9083	0.2247	0.2247
SO2, ppmvd (dry)	0.3177	0.3238	0.3077	1.0862	0.3199	0.3199
SO2, ppmvw (wet)	0.2790	0.2855	0.2743	0.9760	0.2771	0.2771
SO2, lb/h	2.4133	1.9379	1.5250	7.1751	2.1256	2.1256
SO2, lb/MBtu (LHV)	0.0013	0.0013	0.0013	0.0050	0.0013	0.0013
SO2, lb/MBtu (HHV)	0.0012	0.0012	0.0012	0.0045	0.0012	0.0012

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Natural Gas	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	No	Water	Water
Ambient Temperature, F	59	59	59	100	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	566.31	566.31	2.00	566.31	566.31
Combustion Turbine Exhaust - continued						
CTG UHC Emissions (Without Post Combustion Emissions Control)						
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	5.6	5.5	5.7	6.5	5.7	5.7
UHC, ppmvd (dry)	8.0	7.9	7.9	7.8	8.1	8.1
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	15.2	11.9	9.7	12.9	13.4	13.4
UHC, lb/MBtu as CH4 (LHV)	0.0082	0.0080	0.0084	0.0091	0.0083	0.0083
UHC, lb/MBtu as CH4 (HHV)	0.0077	0.0076	0.0079	0.0082	0.0078	0.0078
CTG VOC Emissions (Without Post Combustion Emissions Control)						
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	50%	50%	50%	20%	50%	50%
VOC, ppmvd (dry, 15% O2)	2.8	2.8	2.9	1.3	2.8	2.8
VOC, ppmvd (dry)	4.0	4.0	3.9	1.6	4.0	4.0
VOC, ppmvw (wet)	3.5	3.5	3.5	1.4	3.5	3.5
VOC, lb/h as CH4	7.6	5.9	4.9	2.6	6.7	6.7
VOC, lb/MBtu as CH4 (LHV)	0.0041	0.0040	0.0042	0.0018	0.0041	0.0041
VOC, lb/MBtu as CH4 (HHV)	0.0039	0.0038	0.0039	0.0016	0.0039	0.0039
CTG PM10 Emissions (without the Effects of SO2 Oxidation)						
Percent margin included in PM10 emissions below	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only						
PM10, lb/h	17.0	17.0	17.0	9.0	17.0	17.0
PM10, lb/MBtu (LHV)	0.0092	0.0115	0.0146	0.0063	0.0105	0.0105
PM10, lb/MBtu (HHV)	0.0087	0.0108	0.0137	0.0057	0.0098	0.0098
PM10 Emissions - Front and Back Half Catch						
PM10, lb/h	34.0	34.0	34.0	18.0	34.0	34.0
PM10, lb/MBtu (LHV)	0.0185	0.0230	0.0292	0.0127	0.0210	0.0210
PM10, lb/MBtu (HHV)	0.0173	0.0216	0.0274	0.0114	0.0197	0.0197
HRSG Duct Burners						
Duct Burner Fuel						
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	0.0	0.0	485.0
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	0.0	0.0	538.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0	0	23,300
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00
Duct Burner Emissions						
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	2.753
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000	0.000	0.382
DB NOx, lb/h	0.00	0.00	0.00	0.00	0.00	43.00
DB CO, lb/h	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*21.50*
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	32.30
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	2.20
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	5.40
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	12.90

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CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Natural Gas	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	No	Water	Water
Ambient Temperature, F	59	59	59	100	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	566.31	566.31	2.00	566.31	566.31
Stack Emissions						
Stack Exhaust Analysis - Volume Basis - Wet						
Ar	0.89%	0.89%	0.90%	0.91%	0.88%	0.87%
CO_2	5.28%	5.40%	5.19%	3.66%	5.24%	6.36%
H_2O	12.17%	11.83%	10.88%	10.14%	13.39%	15.52%
N_2	70.67%	70.99%	71.64%	72.86%	69.71%	68.90%
O_2	11.00%	10.90%	11.39%	12.42%	10.79%	8.35%
SO_2 (after SO_2 oxidation)	0.000020%	0.000020%	0.000020%	0.000070%	0.000020%	0.000050%
SO_3 (after SO_2 oxidation)	0.000020%	0.000020%	0.000020%	0.000050%	0.000020%	0.000030%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	263	245	243	181	263	249
Stack Diameter, ft (estimated)	18	18	18	18	18	18
Stack Flow, lb/h	3,805,999	2,991,999	2,457,999	3,234,997	3,358,999	3,382,299
Stack Flow, scfm	853,813	670,208	548,953	725,718	757,455	766,091
Stack Flow, acfm	1,188,106	909,069	742,726	895,556	1,053,047	1,045,131
Stack Exit Velocity, ft/s	78.0	80.0	49.0	59.0	69.0	68.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)						
NOx, ppmvd (dry, 15% O_2)	42.0	42.0	42.0	9.0	42.0	37.6
NOx, ppmvd (dry)	59.4	60.5	57.5	10.8	59.8	69.7
NOx, ppmvw (wet)	52.2	53.4	51.3	9.7	51.8	58.9
NOx, lb/h as NO_2 (includes correction adder)	325.5	261.6	206.2	52.5	286.9	329.9
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.1767	0.1769	0.1772	0.0369	0.1768	0.1565
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.1659	0.1661	0.1664	0.0333	0.1660	0.1456
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)						
NOx, ppmvd (dry, 15% O_2)	8.0	8.0	8.0	2.0	8.0	8.0
NOx, ppmvd (dry)	11.3	11.5	11.0	2.4	11.4	14.8
NOx, ppmvw (wet)	9.9	10.2	9.8	2.1	9.9	12.5
NOx, lb/h as NO_2 (includes NOx margin applied to CTG)	62.0	49.8	39.3	11.7	54.6	70.2
NOx, lb/MBtu (LHV) as NO_2 (incl. duct burner fuel)	0.0337	0.0337	0.0338	0.0082	0.0337	0.0333
NOx, lb/MBtu (HHV) as NO_2 (incl. duct burner fuel)	0.0316	0.0316	0.0317	0.0074	0.0316	0.0310
SCR NH_3 slip, ppmvd (dry, 15% O_2)	5.0	5.0	5.0	10.0	5.0	5.0
SCR NH_3 slip, lb/h	14.3	11.5	9.0	21.0	12.6	16.2
Stack CO Emissions						
CO, ppmvd (dry, 15% O_2)	14.1	13.9	14.6	7.5	14.0	15.0
CO, ppmvd (dry)	20.0	20.0	20.0	9.0	20.0	27.8
CO, ppmvw (wet)	17.6	17.6	17.8	8.1	17.3	23.5
CO, lb/h (includes CO margin applied to CTG)	66.6	52.5	43.5	26.1	58.2	79.8
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0361	0.0355	0.0374	0.0184	0.0359	0.0379
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0339	0.0333	0.0351	0.0166	0.0337	0.0352
Stack SO_2 Emissions, after SO_2 Oxidation						
Assumed SO_2 oxidation rate in CO Catalyst, vol%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Assumed SO_2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO_2, ppmvd (dry, 15% O_2)	0.16	0.16	0.16	0.63	0.16	0.30
SO_2, ppmvd (dry)	0.22	0.23	0.21	0.76	0.22	0.55
SO_2, ppmvw (wet)	0.19	0.20	0.19	0.68	0.19	0.47
SO_2, lb/h	1.69	1.35	1.07	5.01	1.48	3.62
SO_2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0009	0.0009	0.0009	0.0035	0.0009	0.0017
SO_2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0009	0.0009	0.0009	0.0032	0.0009	0.0016

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Case Number	60	61	62	63	64	65
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Natural Gas	Distillate	Distillate
CTG Load	100%	75%	50%	100%	100%	100%
CTG Inlet Air Cooling	Evap. Cooler	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	No	Water	Water
Ambient Temperature, F	59	59	59	100	100	100
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Fuel Sulfur Content (grains/100 standard cubic feet)	566.31	566.31	566.31	2.00	566.31	566.31

Stack Emissions - continued

	60	61	62	63	64	65
Stack UHC Emissions						
UHC, ppmvd (dry, 15% O2)	5.6	5.5	5.7	6.5	5.7	15.0
UHC, ppmvd	8.0	7.9	7.9	7.8	8.1	27.9
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	23.5
UHC, lb/h as CH4 (includes correction adder)	15.2	11.9	9.7	12.9	13.4	45.7
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0082	0.0080	0.0084	0.0091	0.0083	0.0217
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0077	0.0076	0.0079	0.0082	0.0078	0.0202
Stack VOC Emissions						
VOC, ppmvd (dry, 15% O2)	2.8	2.8	2.9	1.3	2.8	2.9
VOC, ppmvd (dry)	4.0	4.0	3.9	1.6	4.0	5.4
VOC, ppmvw (wet)	3.5	3.5	3.5	1.4	3.5	4.6
VOC, lb/h as CH4 (includes VOC correction as applied to CTG)	7.6	5.9	4.9	2.6	6.7	8.9
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0041	0.0040	0.0042	0.0018	0.0041	0.0042
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0039	0.0038	0.0039	0.0016	0.0039	0.0039
PM10 without the Effects of SO2 oxidation						
PM10 Emissions - Front Half Catch Only						
PM10, lb/h	17.0	17.0	17.0	9.0	17.0	22.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0092	0.0115	0.0146	0.0063	0.0105	0.0108
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0087	0.0108	0.0137	0.0057	0.0098	0.0099
PM10 Emissions - Front and Back Half Catch						
PM10, lb/h	34.0	34.0	34.0	18.0	34.0	46.9
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0230	0.0292	0.0127	0.0210	0.0223
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0173	0.0216	0.0274	0.0114	0.0197	0.0207
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]						
PM10 Emissions - Front Half Catch Only						
PM10, lb/h	17.0	17.0	17.0	9.0	17.0	22.4
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0092	0.0115	0.0146	0.0063	0.0105	0.0106
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0087	0.0108	0.0137	0.0057	0.0098	0.0099
PM10 Emissions - Front and Back Half Catch						
PM10, lb/h	36.7	36.2	35.7	26.2	36.4	51.2
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0200	0.0245	0.0307	0.0184	0.0224	0.0243
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0187	0.0230	0.0288	0.0166	0.0211	0.0226
Total Effects of SO2 Oxidation						
Total SO2 to SO3 conversion rate, %vol	44.1%	44.1%	44.1%	44.1%	44.1%	36.7%
Total Amount of SO2 converted to SO3, lb/h	1.33	1.07	0.84	3.96	1.17	2.10
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	2.75	2.20	1.74	8.16	2.42	4.32
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	2.04	1.64	1.29	6.06	1.80	3.21

Post Combustion Emissions Control Equipment

	60	61	62	63	64	65
Selective Catalytic Reduction (SCR)						
NOx Removed in SCR, %wt	81.0%	81.0%	81.0%	77.8%	81.0%	78.7%
NOx removed in SCR, lb/h	263.5	211.8	166.9	40.9	232.2	259.7
Ammonia Slip, lb/h	14.3	11.5	9.0	21.0	12.6	16.2

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas
5. The CTG performance is from GTP, a General Electric estimation program.
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

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Case Number	66	67	68	69
CTG Model	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	40%	40%	40%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No
Ambient Temperature, F	100	73	59	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Ambient Conditions				
Ambient Temperature, F	100.0	73.0	59.0	26.0
Ambient Relative Humidity, %	48.4	81.5	60.0	100.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690
Combustion Turbine Performance				
CTG Performance Reference	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	100.0	73.0	59.0	26.0
CTG Compr. Inlet Relative Humidity, %	48.5	81.6	60.2	100.0
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	5.2	5.6	5.8	6.0
CTG Load Level (percent of Base Load)	40%	40%	40%	40%
Gross CTG Output, kW	57,800	64,800	67,600	73,400
Gross CTG Heat Rate, Btu/kWh (LHV)	14,440	13,740	13,520	13,140
Gross CTG Heat Rate, Btu/kWh (HHV)	16,018	15,241	14,997	14,576
CTG Heat Input, MBtu/h (LHV)	834.6	890.4	914.0	964.5
CTG Heat Input, MBtu/h (HHV)	925.8	987.6	1,013.8	1,069.9
CTG Water/Steam Injection Flow, lb/h	0	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	2,092,000	2,161,000	2,197,000	2,248,000
CTG Exhaust Temperature, F	1,200	1,200	1,200	1,200
Combustion Turbine Fuel				
Total CTG Fuel Flow, lb/h	40,100	42,770	43,910	46,330
CTG Fuel Temperature, F	365	365	365	365
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093
CTG Fuel Composition (Ultimate Analysis by Weight)				
Ar	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust				
CTG Exhaust Analysis (Volume Basis - Wet)				
Ar	0.92%	0.93%	0.94%	0.94%
CO2	3.32%	3.44%	3.49%	3.60%
H2O	9.51%	8.85%	7.76%	7.45%
N2	73.11%	73.71%	74.60%	74.92%
O2	13.14%	13.07%	13.22%	13.08%
SO2, (after SO2 oxidation)	0.00009%	0.00009%	0.00009%	0.00010%
SO3, (after SO2 oxidation)	0.00002%	0.00002%	0.00002%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.23	28.31	28.44	28.48
Specific Volume, ft^3/lb	42.40	42.23	42.03	41.94
Specific Volume, scf/lb	13.44	13.40	13.34	13.32
Exhaust Gas Flow, acfm	1,478,347	1,520,964	1,538,999	1,571,352
Exhaust Gas Flow, acfm	468,608	482,623	488,466	499,056
CTG NOx Emissions (Without Post Combustion Emissions Control)				
Additonal Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	81.00	93.00	9.00	9.00
NOx, ppmvd (dry)	87.40	103.20	10.00	10.30
NOx, ppmvw (wet)	79.10	94.10	9.20	9.50
NOx, lb/h as NO2	269.7	330.3	33.0	35.0
NOx, lb/MBtu (LHV)	0.3232	0.3710	0.0361	0.0363
NOx, lb/MBtu (HHV)	0.2913	0.3345	0.0326	0.0327
CTG CO Emissions (Without Post Combustion Emissions Control)				
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	25.80	24.20	8.10	7.90
CO, ppmvd (dry)	27.80	26.90	9.00	9.00
CO, ppmvw (wet)	25.20	24.50	8.30	8.30
CO, lb/h	52.3	52.3	18.0	18.4
CO, lb/MBtu (LHV)	0.0626	0.0588	0.0197	0.0191
CO, lb/MBtu (HHV)	0.0565	0.0530	0.0178	0.0172
CTG SO2 Emissions (After SO2 Oxydation, Without Post Combustion Emissions Control)				
Additonal Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in CTG, vol%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9083	0.9083	0.9083	0.9083
SO2, ppmvd (dry)	0.9803	1.0079	1.0101	1.0398
SO2, ppmvw (wet)	0.8871	0.9187	0.9318	0.9623
SO2, lb/h	4.2114	4.4918	4.6115	4.8657
SO2, lb/MBtu (LHV)	0.0050	0.0050	0.0050	0.0050
SO2, lb/MBtu (HHV)	0.0045	0.0045	0.0045	0.0045

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Case Number	66	67	68	69
CTG Model	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	40%	40%	40%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No
Ambient Temperature, F	100	73	59	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust - continued				
CTG UHC Emissions (Without Post Combustion Emissions Control)				
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	22.0	20.5	6.8	6.6
UHC, ppmvd (dry)	23.8	22.8	7.6	7.6
UHC, ppmvw (wet)	21.5	20.8	7.0	7.0
UHC, lb/h as CH4	25.6	25.4	9.0	9.0
UHC, lb/MBtu as CH4 (LHV)	0.0306	0.0285	0.0096	0.0093
UHC, lb/MBtu as CH4 (HHV)	0.0276	0.0257	0.0089	0.0084
CTG VOC Emissions (Without Post Combustion Emissions Control)				
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%
VOC percentage of UHC	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	4.4	4.1	1.4	1.3
VOC, ppmvd (dry)	4.8	4.6	1.5	1.5
VOC, ppmvw (wet)	4.3	4.2	1.4	1.4
VOC, lb/h as CH4	5.1	5.1	1.8	1.8
VOC, lb/MBtu as CH4 (LHV)	0.0061	0.0057	0.0020	0.0019
VOC, lb/MBtu as CH4 (HHV)	0.0055	0.0051	0.0018	0.0017
CTG PM10 Emissions (without the Effects of SO2 Oxidation)				
Percent margin included in PM10 emissions below	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only				
PM10, lb/h	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0108	0.0101	0.0096	0.0093
PM10, lb/MBtu (HHV)	0.0097	0.0091	0.0089	0.0084
PM10 Emissions - Front and Back Half Catch				
PM10, lb/h	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0216	0.0202	0.0197	0.0187
PM10, lb/MBtu (HHV)	0.0194	0.0182	0.0178	0.0168
HRSG Duct Burners				
Duct Burner Fuel				
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816
Duct Burner Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091
Duct Burner Fuel Composition (Ultimate Analysis by Weight)				
Ar	0.00%	0.00%	0.00%	0.00%
C	73.76%	73.76%	73.76%	73.76%
H2	24.01%	24.01%	24.01%	24.01%
N2	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%
S	0.00657%	0.00657%	0.00657%	0.00657%
Total	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Duct Burner Emissions				
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	10.0%	10.0%	10.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.000	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00

FMPA
Treasure Coast Energy Center Unit 1
Black & Veatch Project 138859.0030
1x1 Emissions Estimates

Case Number	66	67	68	69
CTG Model	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	40%	40%	40%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No
Ambient Temperature, F	100	73	59	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Stack Emissions				
Stack Exhaust Analysis - Volume Basis - Wet				
Ar	0.92%	0.93%	0.94%	0.94%
CO2	3.32%	3.44%	3.49%	3.60%
H2O	9.51%	8.85%	7.76%	7.45%
N2	73.11%	73.71%	74.60%	74.92%
O2	13.14%	13.07%	13.22%	13.06%
SO2 (after SO2 oxidation)	0.000080%	0.000080%	0.000080%	0.000080%
SO3 (after SO2 oxidation)	0.000030%	0.000030%	0.000040%	0.000040%
Total	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	165	162	158	155
Stack Diameter, ft (estimated)	18	18	18	18
Stack Flow, lb/h	2,091,998	2,160,998	2,196,998	2,247,998
Stack Flow, scfm	468,608	482,623	488,466	499,056
Stack Flow, acfm	563,097	577,347	580,740	590,100
Stack Exit Velocity, ft/s	37.0	38.0	38.0	39.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)				
NOx, ppmvd (dry, 15% O2)	81.0	93.0	9.0	9.0
NOx, ppmvd (dry)	87.4	103.2	10.0	10.3
NOx, ppmvw (wet)	79.1	94.1	9.2	9.5
NOx, lb/h as NO2 (includes correction adder)	269.7	330.3	33.0	35.0
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.3232	0.3710	0.0361	0.0363
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.2913	0.3345	0.0326	0.0327
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)				
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	2.2	2.2	2.2	2.3
NOx, ppmvw (wet)	2.0	2.0	2.1	2.1
NOx, lb/h as NO2 (includes NOx margin applied to CTG)	6.7	7.1	7.3	7.8
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0081
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0073
SCR NH3 slip, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0
SCR NH3 slip, lb/h	12.3	13.1	13.5	14.2
Stack CO Emissions				
CO, ppmvd (dry, 15% O2)	25.8	24.2	8.1	7.9
CO, ppmvd (dry)	27.8	26.9	9.0	9.0
CO, ppmvw (wet)	25.2	24.5	8.3	8.3
CO, lb/h (includes CO correction as applied to CTG and margin)	52.3	52.3	18.0	18.4
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0626	0.0588	0.0197	0.0191
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0566	0.0530	0.0178	0.0172
Stack SO2 Emissions, after SO2 Oxidation				
Assumed SO2 oxidation rate in CO Catalyst, vol%	0.0%	0.0%	0.0%	0.0%
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.79	0.79	0.79	0.79
SO2, ppmvd (dry)	0.86	0.88	0.88	0.91
SO2, ppmvw (wet)	0.77	0.80	0.81	0.84
SO2, lb/h	3.68	3.92	4.03	4.25
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0044	0.0044	0.0044	0.0044
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0040	0.0040	0.0040	0.0040

FMPA
Treasure Coast Energy Center Unit 1
Black & Veatch Project 138859.0030
1x1 Emissions Estimates

Case Number	66	67	68	69
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CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	40%	40%	40%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No
Ambient Temperature, F	100	73	59	26
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00
Stack Emissions - continued				
Stack UHC Emissions				
UHC, ppmvd (dry, 15% O2)	22.0	20.5	6.8	6.6
UHC, ppmvd	23.8	22.8	7.6	7.6
UHC, ppmvw	21.5	20.8	7.0	7.0
UHC, lb/h as CH4 (includes correction adder)	25.6	25.4	9.0	9.0
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0306	0.0285	0.0098	0.0093
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0276	0.0257	0.0089	0.0084
Stack VOC Emissions				
VOC, ppmvd (dry, 15% O2)	4.4	4.1	1.4	1.3
VOC, ppmvd (dry)	*4.8*	*4.6*	*1.5*	*1.5*
VOC, ppmvw (wet)	4.3	4.2	1.4	1.4
VOC, lb/h as CH4 (includes correction adder)	5.1	5.1	1.8	1.8
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0061	0.0057	0.0020	0.0019
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0055	0.0051	0.0018	0.0017
PM10 without the Effects of SO2 oxidation				
PM10 Emissions - Front Half Catch Only				
PM10, lb/h	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0108	0.0101	0.0098	0.0093
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0097	0.0091	0.0089	0.0084
PM10 Emissions - Front and Back Half Catch				
PM10, lb/h	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0216	0.0202	0.0197	0.0187
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0194	0.0182	0.0178	0.0168
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]				
PM10 Emissions - Front Half Catch Only				
PM10, lb/h	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0108	0.0101	0.0098	0.0093
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0097	0.0091	0.0089	0.0084
PM10 Emissions - Front and Back Half Catch				
PM10, lb/h	21.3	21.5	21.6	21.8
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0255	0.0241	0.0236	0.0226
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0230	0.0218	0.0213	0.0204
Total Effects of SO2 Oxidation				
Total SO2 to SO3 conversion rate, %vol	30.2%	30.2%	30.2%	30.2%
Total Amount of SO2 converted to SO3, lb/h	1.59	1.69	1.74	1.83
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	3.28	3.49	3.59	3.78
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	2.43	2.59	2.66	2.81
Post Combustion Emissions Control Equipment				
Selective Catalytic Reduction (SCR)				
NOx Removed in SCR, %wt	97.5%	97.8%	77.8%	77.8%
NOx removed in SCR, lb/h	263.1	323.2	25.7	27.2
Ammonia Slip, lb/h	*12.3*	*13.1*	*13.5*	*14.2*

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.698 psia. Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from GTP, a General Electric estimation program. The CO, UHC & VOC emissions at 40 percent load were adjusted based on engineering judgement.
6. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
7. The VOC/UHC ratio is assumed to be 20% for NG and 50% for distillate.
8. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that *100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.*
9. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, were applicable.
10. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on low NOx duct burner emissions data (provided by Forney).
11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch.
12. As requested the SCR was designed to reduce the NOx stack emissions to 2 and 8 ppmvd@15%O2 when firing NG and Distillate, respectively.
13. The emissions estimate is based on FGT gas with a maximum sulfur content of 2.0 grains/100scf.

FMPA - Treasure Coast Energy Center (Unit 1)

Determination of Representative Emission and Stack Parameters at 100% Load

Distillate Oil

Ambient Temperature - 100 °F

Case Number:	2	8	64	65	**Worst Case Parameters**				
Evap. Cooler	X	X							
Duct Burner Firing	X			X					
Exit Temp (°F)	250	266	263	249	Exit Temp	249.0	°F	393.71	K
Exit Velocity (ft/s)	71	72	69	68	Exit Velocity	68.0	ft/s	20.7264	m/s
Emissions (lb/h)					Emissions				
NOX	73.2	57.1	54.6	70.2	NOX	73.2	lb/h	9.2230	g/s
CO	82.3	60.1	58.2	79.8	CO	82.3	lb/h	10.3696	g/s
PM/PM10	49.8	35.7	36.4	51.2	PM/PM10	51.2	lb/h	6.4511	g/s
SO2	5.9	2.8	2.7	5.7	SO2	5.9	lb/h	0.7446	g/s

Ambient Temperature - 73 °F

Case Number:	6	12			**Worst Case Parameters**				
Evap. Cooler	X	X							
Duct Burner Firing	X								
Exit Temp (°F)	251	265			Exit Temp	251.0	°F	394.82	K
Exit Velocity (ft/s)	74	75			Exit Velocity	74.0	ft/s	22.5552	m/s
Emissions (lb/h)					Emissions				
NOX	76.0	60.0			NOX	76.0	lb/h	9.5758	g/s
CO	86.2	64.0			CO	86.2	lb/h	10.8610	g/s
PM/PM10	49.9	35.8			PM/PM10	49.9	lb/h	6.2873	g/s
SO2	6.0	2.9			SO2	6.0	lb/h	0.7616	g/s

Ambient Temperature - 59 °F

Case Number:	57	58	59	60	**Worst Case Parameters**				
Evap. Cooler		X		X					
Duct Burner Firing	X	X							
Exit Temp (°F)	251	251	262	263	Exit Temp	251.0	°F	394.82	K
Exit Velocity (ft/s)	76	77	77	78	Exit Velocity	76.0	ft/s	23.1648	m/s
Emissions (lb/h)					Emissions				
NOX	77.3	78.0	61.4	62.0	NOX	78.0	lb/h	9.8278	g/s
CO	88.0	88.7	65.9	66.6	CO	88.7	lb/h	11.1760	g/s
PM/PM10	51.9	52.0	36.7	36.7	PM/PM10	52.0	lb/h	6.5519	g/s
SO2	6.1	6.2	3.0	3.0	SO2	6.2	lb/h	0.7771	g/s

Ambient Temperature - 26 °F

Case Number:	4	10			**Worst Case Parameters**				
Evap. Cooler									
Duct Burner Firing	X								
Exit Temp (°F)	252	263			Exit Temp	252.0	°F	395.37	K
Exit Velocity (ft/s)	81	82			Exit Velocity	81.0	ft/s	24.6888	m/s
Emissions (lb/h)					Emissions				
NOX	81.1	65.1			NOX	81.1	lb/h	10.2184	g/s
CO	92.4	70.3			CO	92.4	lb/h	11.6422	g/s
PM/PM10	50.0	36.0			PM/PM10	50.0	lb/h	6.2999	g/s
SO2	6.3	3.1			SO2	6.3	lb/h	0.7921	g/s

Natural Gas

Ambient Temperature - 100 °F

Case Number:	1	7	45	63	**Worst Case Parameters**				
Evap. Cooler	X	X							
Duct Burner Firing	X		X						
Exit Temp (°F)	168	184	166	181	Exit Temp	166.0	°F	347.59	K
Exit Velocity (ft/s)	60	61	58	59	Exit Velocity	58.0	ft/s	17.6764	m/s
Emissions (lb/h)					Emissions				
NOX	16.1	12.2	15.6	11.7	NOX	16.1	lb/h	2.0288	g/s
CO	49.2	27.0	48.6	26.1	CO	49.2	lb/h	6.1991	g/s
PM/PM10	38.0	23.8	38.0	26.2	PM/PM10	38.0	lb/h	4.7879	g/s
SO2	12.6	9.4	12.2	9.0	SO2	12.6	lb/h	1.5816	g/s

Ambient Temperature - 73 °F

Case Number:	5	11			**Worst Case Parameters**				
Evap. Cooler	X	X							
Duct Burner Firing	X								
Exit Temp (°F)	168	182			Exit Temp	168.0	°F	348.71	K
Exit Velocity (ft/s)	63	63			Exit Velocity	63.0	ft/s	19.2024	m/s
Emissions (lb/h)					Emissions				
NOX	16.5	12.7			NOX	16.5	lb/h	2.0790	g/s
CO	50.1	28.3			CO	50.1	lb/h	6.3125	g/s
PM/PM10	38.0	24.1			PM/PM10	38.0	lb/h	4.7879	g/s
SO2	12.9	9.8			SO2	12.9	lb/h	1.6246	g/s

Ambient Temperature - 59 °F

Case Number:	50	51	52	53	**Worst Case Parameters**				
Evap. Cooler	X	X							
Duct Burner Firing	X		X						
Exit Temp (°F)	167	180	166	180	Exit Temp	166.0	°F	347.59	K
Exit Velocity (ft/s)	65	66	64	65	Exit Velocity	64.0	ft/s	19.5072	m/s
Emissions (lb/h)					Emissions				
NOX	16.9	13.1	16.7	12.9	NOX	16.9	lb/h	2.1294	g/s
CO	51.4	30.0	51.0	29.4	CO	51.4	lb/h	6.4763	g/s
PM/PM10	37.9	24.3	38.0	24.2	PM/PM10	38.0	lb/h	4.7879	g/s
SO2	13.2	10.2	13.1	10.0	SO2	13.2	lb/h	1.6630	g/s

Ambient Temperature - 26 °F

Case Number:	3	9			**Worst Case Parameters**				
Evap. Cooler									
Duct Burner Firing	X								
Exit Temp (°F)	167	179			Exit Temp	167.0	°F	348.15	K
Exit Velocity (ft/s)	68	69			Exit Velocity	68.0	ft/s	20.7264	m/s
Emissions (lb/h)					Emissions				
NOX	17.5	13.8			NOX	17.5	lb/h	2.2050	g/s
CO	52.3	31.4			CO	52.3	lb/h	6.5897	g/s
PM/PM10	38.0	24.6			PM/PM10	38.0	lb/h	4.7879	g/s
SO2	13.6	10.7			SO2	13.6	lb/h	1.7189	g/s

NOx, lb/hr (w/ effects of SCR)
CO, lb/hr
PM_{10}, lb/hr (w/ effects of SO_2 oxidation)
SO_2, lb/hr (w/out effects of SO_2 oxidation)

Appendix C
Tanks Model Output

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	FT-001
City:	Vero Beach
State:	Florida
Company:	Florida Municipal Power Agency
Type of Tank:	Vertical Fixed Roof Tank
Description:	Treasure Coast Energy Center, Fuel Oil Storage Tank 001

Tank Dimensions

Shell Height (ft):	40.00
Diameter (ft):	70.00
Liquid Height (ft):	35.00
Avg. Liquid Height (ft):	35.00
Volume (gallons):	1,000,000.00
Turnovers:	6.85
Net Throughput (gal/yr):	6,846,809.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	70.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Vero Beach, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.17	69.18	79.18	72.43	0.0102	0.0087	0.0119	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	106.5506
Vapor Space Volume (cu ft):	37,719.9454
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0336
Vented Vapor Saturation Factor:	0.9947
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	37,719.9454
Tank Diameter (ft):	*70.0000*
Vapor Space Outage (ft):	9.8013
Tank Shell Height (ft):	40.0000
Average Liquid Height (ft):	35.0000
Roof Outage (ft):	4.8013
Roof Outage (Dome Roof)	
Roof Outage (ft):	4.8013
Dome Radius (ft):	70.0000
Shell Radius (ft):	35.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0102
Daily Avg. Liquid Surface Temp. (deg. R):	533.8411
Daily Average Ambient Temp. (deg. F):	72.4083
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0983
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,304.2500
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0336
Daily Vapor Temperature Range (deg. R):	19.9722
Daily Vapor Pressure Range (psia):	0.0032
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0102
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0087
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0119
Daily Avg. Liquid Surface Temp. (deg R):	533.8411
Daily Min. Liquid Surface Temp. (deg R):	528.8481
Daily Max. Liquid Surface Temp. (deg R):	538.8342
Daily Ambient Temp. Range (deg. R):	19.1167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9947
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0102
Vapor Space Outage (ft):	9.8013

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Working Losses (lb):	216.5159
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0102
Annual Net Throughput (gal/yr.):	6,846,809.000 0
Annual Turnovers:	6.8468
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,000,000.000 0
Maximum Liquid Height (ft):	35.0000
Tank Diameter (ft):	70.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	323.0665

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	216.52	106.55	323.07

Appendix D

Calculating Realistic PM_{10} Emissions from Cooling Towers

Joel Reisman and Gordon Frisbie

Abstract 216

Air and Waste Management Association 94th Annual Conference and Exhibition in Orlando, Florida, June 25-28, 2001

Calculating Realistic PM_{10} Emissions from Cooling Towers

Abstract No. 216 Session No. AM-1b

Joel Reisman and Gordon Frisbie
Greystone Environmental Consultants, Inc., 650 University Avenue, Suite 100, Sacramento, California 95825

ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM_{10}) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42[1] , which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM_{10}. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM_{10} emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM_{10} modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM_{10} non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM_{10} emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM_{10} emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42[1] provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM_{10} range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$PM = \text{Water Circulation Rate} \times \text{Drift Rate} \times \text{TDS} \qquad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$PM = 146{,}000 \text{ gpm} \times 8.34 \text{ lb water/gal} \times 0.0006/100 \times 7{,}700 \text{ lb solids}/10^6 \text{ lb water} \times 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM_{10}, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM_{10}.

COMPUTING THE PM_{10} FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM_{10} can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull[2], 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore, this size distribution data can be assumed to be conservative for predicting the fraction of PM_{10} in the total cooling tower PM emissions.

In calculating PM_{10} emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; $1.0\ \text{g/cm}^3$ or $1.0 * 10^{-6}\ \mu g / \mu m^3$.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm^3).

Using the formula for the volume of a sphere, $V = 4\pi r^3/3$, and the density of pure water, $\rho_w = 1.0\ \text{g/cm}^3$, the following equations can be used to derive the solid particulate diameter, D_p, as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d :

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \quad [2]$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet}) \quad [3]$$

substituting,

$$\text{Mass of solids in drift} = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \quad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})\ (\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \quad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \quad [6]$$

Solving for D_p:

$$D_p = D_d\ [(\text{TDS})(\rho_w / \rho_{TDS})]^{1/3} \quad [7]$$

Where,

TDS is in units of ppmw
D_p = diameter of solid particle, micrometers (μm)
D_d = diameter of drift droplet, μm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 μm in diameter, we conclude that approximately 14.9 percent of the mass emissions are equal to or smaller than PM_{10}. The balance of the solid particulate are particulate greater than 10 μm. Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm.

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

[1] Bracketed numbers refer to equation number in text.

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42[1] Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift droplet size distribution, a method is now available for calculating realistic PM_{10} emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM10

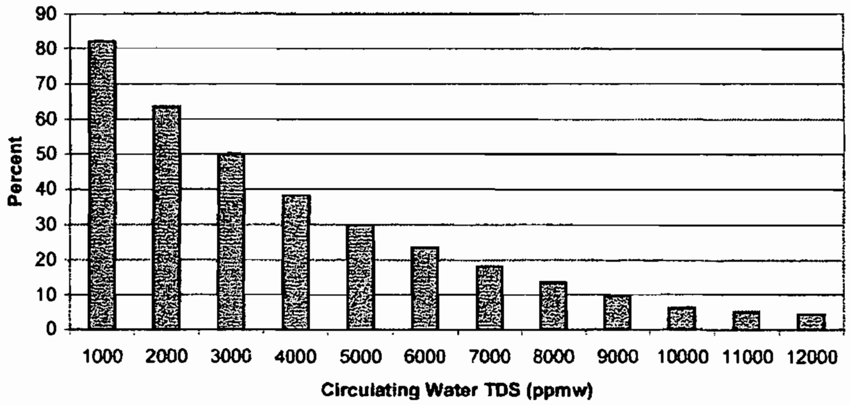
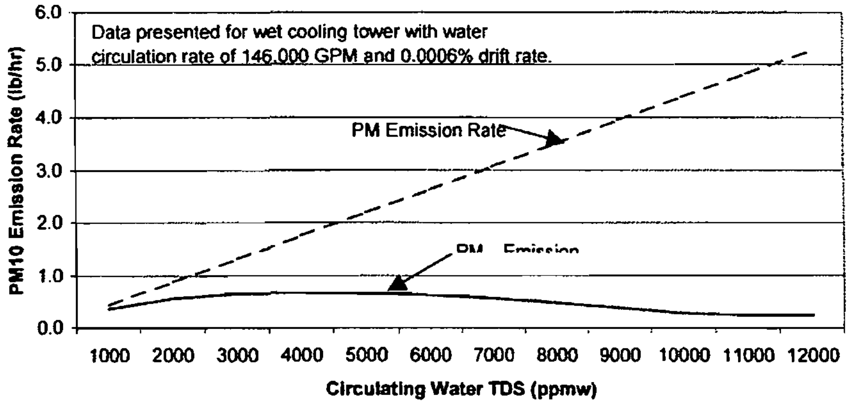


Figure 2: PM_{10} Emission Rate vs. TDS



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KEY WORDS

Drift
Drift eliminators
Cooling tower
PM_{10} emissions
TDS

Appendix E
Best Available Control Technology

Best Available Control Technology Analysis
for
Treasure Coast Energy Center
Unit 1
Combined Cycle Combustion Turbine

Submitted by

Florida Municipal Power Agency

April 2005
Project No. 138859

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ENERGY WATER INFORMATION GOVERNMENT

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1.0 Executive Summary

The 1977 Clean Air Act Amendment (CAAA) established revised conditions for the approval of preconstruction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed on new major sources or modifications to existing major sources for all pollutants regulated under the CAAA. Under the BACT process, the chosen technology cannot be less stringent than standards established by New Source Performance Standards (NSPS). The proposed Florida Municipal Power Agency (FMPA) Treasure Coast Energy Center (TCEC) Unit 1 includes one combined cycle combustion turbine with heat recovery steam generator (CTG/HRSG) that is subject to the BACT process. In addition, the Project will include an auxiliary boiler, safe shutdown diesel generator, mechanical draft cooling tower and emergency diesel engine fire pump. This document presents the BACT analysis and emissions control conclusions for the Project. The following is a summary of the proposed BACT determinations and associated emission rates for Unit 1, auxiliary boiler, safe shutdown diesel generator, mechanical draft cooling tower, and emergency diesel engine fire pump.

The Project will employ one GE Model PG7241 (FA) Combustion Turbine Generator (CTG) operating in combined cycle mode followed by a HRSG with supplemental duct burners. Unit 1 will fire natural gas primarily with up to 500 hours per year of ultra-low sulfur (ULS) fuel oil (0.0015 percent sulfur by weight) as a backup fuel. The duct burners will utilize only natural gas as the fuel source. Emissions for the BACT analysis are based on Unit 1 firing natural gas a maximum of 8,760 hours per year. The unit will operate between 40 and 100 percent of full load. The BACT analysis for Unit 1 resulted in the following determination:

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of selective catalytic reduction (SCR) to achieve NO_x emissions of 2.0 ppmvd at 15 percent O_2 while firing natural gas and 8.0 ppmvd at 15 percent O_2 while firing ultra-low sulfur fuel oil.
- Carbon monoxide (CO) emissions--BACT analysis was determined to be the use of good combustion controls while firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight.

- Volatile organic compounds (VOC) emissions--The emissions of VOCs will be less than the major source PSD threshold level. Therefore a BACT analysis for VOCs is not required for Unit 1.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of natural gas and ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight.
- Sulfuric acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls while firing both natural gas and ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight.

The TCEC Unit 1 Project includes the installation of one 7.2 MBtu/h auxiliary boiler. The auxiliary boiler, utilized for support of the steam turbine generator, will fire only natural gas a maximum of 8,760 hours per year. BACT for the auxiliary boiler emissions was determined to be the use of good combustion controls while firing natural gas.

The TCEC Unit 1 Project includes the installation of one 500 kW safe shutdown diesel generator. The generator will utilize ultra-low sulfur fuel oil and will be employed on an emergency need basis. BACT for the safe shutdown diesel engine generator was determined to be the use of good combustion controls.

The TCEC Unit 1 Project includes the installation of one mechanical draft cooling tower. BACT for the mechanical draft cooling tower will be design of the cooling tower to minimize the cooling tower drift to less than 0.0005 percent of circulating water flow rate.

The TCEC Unit 1 Project includes the installation of one 300 hp emergency diesel engine fire pump. The fire pump will utilize ultra-low sulfur fuel oil and will be employed on an emergency need basis. BACT for the emergency diesel engine fire pump was determined to be the use of good combustion controls.

2.0 Project Description

Treasure Coast Energy Center Unit 1 (hereinafter referred to as Unit 1) to be installed by Florida Municipal Power Agency will consist of one GE Model PG7241 (FA) combustion turbine generator operating in combined cycle mode followed by a HRSG (CTG/HRSG).

The HRSG will utilize natural gas fired duct burners for supplemental heating of the flue gas for combined cycle operation.

The output rating of Unit 1 will be nominally 300 MW at 100 percent load and 73° F conditions. The proposed operating scenario for Unit 1 is 8,760 hours per year of natural gas operation with or without duct burner firing and up to 500 hours per year of operation on ultra-low sulfur fuel oil (combustion turbine only) with or without duct burner firing. The duct burners will fire only natural gas. The unit will be subject to frequent startups and will operate between 40 and 100 percent of full load. The duct burners in the HRSG will have a maximum rating of 545 MBtu/h (HHV) while firing natural gas at 100 percent load and 73° F conditions.

3.0 Basis of Unit 1 BACT Analysis

This section describes the basis for the Unit 1 BACT analysis. Information is provided on the BACT methodology and approach used as well as the parameters and factors used in developing the analysis. The following is a summary of the regulatory requirements and Project assumptions on which this BACT analysis is based.

3.1 Regulatory and Methodology Basis

As defined in the air permit application, operation of Unit 1 will result in an increase in the potential to emit emissions of NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 (sulfuric acid mist) in excess of the PSD significant emission rate threshold levels set for these pollutants. As required by PSD, for a new PSD major source, a BACT analysis is required for those pollutants with potential emission increases greater than the applicable PSD significant emission rate thresholds.

BACT is defined in Rule 62-210.200(37), F.A.C. as:

"Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes, and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."

However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS), which for NO_x is 0.39 lb/MWh when firing natural gas and 1.2 lb/MWh when firing distillate oil. These limits are given in proposed NSPS Subpart KKKK, published in the February 18, 2005 Federal Register.

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the control technology alternatives that are technically feasible for the source category in question. Technologies required under the Lowest Achievable Emission Rate (LAER) for the source category must be considered when determining the control technology for the pollutant in question. LAER determinations, although not applicable to Unit 1, represent the top control alternatives under the BACT analysis process. A LAER determination would be required if Unit 1 was located in a non-attainment area.

Federal and state ambient air quality standards, emission limitations, and other applicable regulations must be met by the technology chosen as BACT. The following criteria are given in Rule 62-212.400(6)(a), F.A.C.:

"(6) Best Available Control Technology (BACT).

(a) BACT Determination. Following receipt of a complete application for a permit to construct an air emissions unit or facility which requires a determination of Best Available Control Technology (BACT), the Department shall make a determination of Best Available Control Technology during the permitting process. In making the BACT determination, the Department shall give consideration to:

1. Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

2. All scientific, engineering, and technical material and other information available to the Department.

3. The emission limiting standards or BACT determinations of any other state.

4. The social and economic impact of the application of such technology."

As previously noted, BACT cannot be less stringent than an applicable NSPS standard. The Federal NSPS for combustion turbines with an output greater than 1 MW (40 CFR 60 Subpart KKKK, proposed) establishes applicable NO_x and SO_2 emission limits or standards. No NSPS emission limits have been established for CO, PM/PM_{10}, or H_2SO_4. The following standards have been established by NSPS for Subpart KKKK units with an output greater than 30 MW:

- NO_x allowable limit = 0.39 lb/MWh when firing natural gas and 1.2 lb/MWh when firing distillate oil.
- SO_2 standard of 0.58 lb/MWh regardless of fuel/size or a fuel sulfur limit of 0.05 percent or less sulfur by weight.

3.2 Operations/Emissions Basis

As mentioned previously, the proposed operating scenario for Unit 1 is a maximum 8,760 full load operating hours per year while firing natural gas with or without duct burner firing and a maximum of 500 hour per year while firing ultra-low sulfur distillate fuel oil with or without duct burner firing on natural gas. Table 3-1 shows the baseline emission rates for Unit 1 firing natural gas at 100 percent base load at an average annual site temperature of 73° F. The emissions shown in Table 3-1 are based on the use of dry low

NO_x burners during natural gas firing using evaporative cooling and include emissions from the duct burners. The lb/MBtu values are based on the higher heating value (HHV) of the expected natural gas to be fired and are based on the combined heat input to the combustion turbine and the duct burners. This unit is expected to cycle with frequent startups and will be operated at 40 to 100 percent of full load for up to 8,760 hours per year.

Table 3-1
Baseline Emission Rates for Unit 1

Emission Parameter	Unit 1[a] Natural Gas, 100% Load, Duct Firing, Evaporative Cooling at a 73° F Ambient Temperature
NO_x, ppmvd at 15% O_2	12.2
NO_x, lb/h	100.6
NO_x, lb/Mbtu (HHV)	0.0444
CO, ppmvd at 15% O_2	8.0
CO, lb/h	39.7
CO, lb/Mbtu	0.0175
PM/PM_{10} (front and back), lb/h[b]	35.8
PM/PM_{10} (front and back), lb/Mbtu (HHV)[b]	0.0158
SO_2, lb/h[c]	12.90
SO_2, lb/Mbtu (HHV)[c]	0.0057
H_2SO_4, lb/h[b]	3.47
H_2SO_4, lb/Mbtu[b]	0.0015

[a]Emissions are based on firing natural gas in the CT and HRSG duct burners at 100 percent of base load with evaporative cooling at an ambient temperature of 73° F.

[b]PM/PM_{10} and H_2SO_4 values include the affects of 20 percent SO_2 oxidation in the CT and 10 percent SO_2 oxidation in the duct burner.

[c]SO_2 values do not include the effects of SO_2 oxidation.

3.3 Economic Basis

The economic analyses used to determine the capital and annualized costs of the control technologies were based on USEPA methodologies shown in the USEPA "Best Available Control Technology Draft Guidance Document" (October 1990), "Top Down" Best Available Control Technology Guidance Document" (March 1990), The Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (February 1996, Fifth Edition), internal owner cost factors, and vendor budgetary cost quotes.

Table 3-2 lists the economic criteria used in the analysis of BACT alternatives. The capital recovery factor was calculated based on the present worth discount rate and economic life of the equipment or the assumed catalyst life.

Table 3-2
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	10
Present Worth Discount Rate, percent	7.0
Economic Life, years	20
Capital Recovery Factor, (20 years)	0.0944
SCR Catalyst Life, years	3
$SCONO_x$ Catalyst Life, years	5
CO Catalyst Life, years	3
Catalyst Capital Recovery Factor (3 years)	0.3811
$SCONO_x$ Catalyst Capital Recovery Factor (5 years)	0.2439
Labor Cost, $/man-hour	30
Natural Gas Cost, $/MBtu (2008)	5.47
Aqueous Ammonia Cost, $/ton (2004)	525
Energy Cost, $/kWh (2004)	0.0646
Sales Tax, percent	N/A

4.0 Unit 1 NO_x and CO BACT Analysis

The objective of this analysis is to determine the BACT for NO_x and CO emissions from Unit 1.

Unless otherwise noted, the emission rates described in this section are corrected to 15 percent oxygen.

4.1 NO_x/CO BACT/LAER and Technology Review

A list of the top pertinent BACT/LAER decisions for NO_x is attached in Table A-1 of Appendix A. A review of the BACT/LAER documents (recent Florida permit actions; the California Air Pollution Control Officers Association, 1985 - 2004; and USEPA BACT/LAER Clearinghouse, 1990 - 2004) indicates that the lowest NO_x emissions permitted for a natural gas fired combustion turbine are 2.0 ppmvd for the facilities listed in Table A-1.

The Duke Energy Arlington Valley facility in Arlington, VA, is a recent project that was constructed as listed by the USEPA BACT/LAER Clearinghouse database. The facility consists of two gas fired combined cycle GE Frame 7FA gas turbines. The NO_x emissions are to be controlled by dry low NO_x combustors and selective catalytic reduction (SCR). The units have been permitted at 2.0 ppmvd at 15 percent O_2 with an ammonia slip of 10 ppmvd at 15 percent O_2.

The FPL Turkey Point combined cycle units project in Florida is a recent project that was issued a final permit by the FDEP on February 8, 2005. The project consists of four gas fired combined cycle GE 7FA turbines/HRSGs with duct burner firing. The NO_x emissions are to be controlled by dry low NO_x combustors and selective catalytic reduction (SCR). The units have been permitted at 2.0 ppmvd at 15 percent O_2 with an ammonia slip of 5 ppmvd at 15 percent O_2.

For CO, a list of the top pertinent BACT/LAER decisions is attached in Table A-2 of Appendix A. A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. The 49.5 MW SW 251 B11/12 Siemens-Westinghouse combustion turbine units fire natural gas. The low emissions are achieved by reducing CO emissions by 80 percent (from 9 ppmvd to 1.8) through the use of an oxidation catalyst. It should be noted that the Newark Bay project, which is located in a non-attainment area for CO, represents LAER.

A summary of recent NOx and CO BACT determinations for EPA Region 4 is included as Tables A-3 and A-4, respectively, in Appendix A. These tables were generated using the National Combustion Turbine Spreadsheet maintained by EPA

Region 4. The information in the National Combustion Turbine Spreadsheet was filtered to only show determinations made in Region 4 for combined cycle combustion turbines.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. NO_x emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxide control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Water/Steam Injection.
  - Dry Low-NO_x (DLN) Burners.
  - Xonon.
- Post-Combustion Type:
  - Selective Non-Catalytic Reduction (SNCR).
  - $SCONO_x$.
  - Selective Catalytic Reduction (SCR).

The rationale behind whether the above technologies are evaluated as NO_x control for BACT is included in the following subsections.

4.2.1 Water or Steam Injection

NO_x emissions from Unit 1 can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. A limit exists, however, on the amount of water that can be injected into the system before reliability of the combustion turbine is seriously degraded and operational life is affected. This type of control can also be counterproductive with regard to CO and VOC emissions that are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls, except for certain cases, such as oil firing. Since Unit 1 will fire natural gas as the primary fuel with ultra-low sulfur fuel oil as a back up, water injection will only be used during oil firing and will not be evaluated for the primary operating case of natural gas.

4.2.2 Dry Low-NO_x Burners

NO_x formation can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low-NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN burners because, when firing natural gas, injecting water into the combustion chamber is not necessary to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state of the art for NO_x controls in combustion turbines. This method is exclusively utilized when firing natural gas. This technology will form the base case for the BACT analysis.

4.2.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700° F at full power generation, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This emerging technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers.

Although this technology has been applied to small turbines, such as a Kawasaki M1A-13X (1.5 MW) combustion turbine, it has not been applied to utility size combustion turbines such as proposed for Unit 1. It is expected that application of this technology to utility size combustion turbines will require a period of "scale up" and testing before it can be determined that this technology can demonstrate in practice a given NO_x emission limit. Because this technology has not been applied to utility size combustion turbines firing natural gas, it is not considered to be technically feasible for

Unit 1. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,500° to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (ammonia slip). Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the combustion turbine proposed for this project (approximately 1,200° F) is less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this BACT analysis.

4.2.5 SCONO$_x$

A second, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with ABB Alstom Power is SCONO$_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia.

The SCONO$_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700° F. ABB Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The SCONO$_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption SCOSO$_x$ catalyst. The SCOSO$_x$ catalyst is located upstream of the SCONO$_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated or "washed" every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the $SCOSO_x$ catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module in a potassium carbonate reagent tank, which is the active ingredient of the catalyst. The $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is uncertain how often this will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately 10 months on a small LM-2500 combined cycle combustion turbine unit before the $SCONO_x$ system was taken out of service because of poor regeneration gas distribution.

The USEPA has stated its concerns (November 19, 1999 letter from USEPA Region I) with the technical uncertainties of the $SCONO_x$ system and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. The combustion turbine proposed for this project is approximately 170 MW, which is outside the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. However in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for NO_x control.

4.2.6 Selective Catalytic Reduction

Another post-combustion method of NO_x control is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CTG/HRSG projects for the past ten years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades ammonia slip will increase to approximately 5 -10 ppmvd (dependent on system design), ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadium/titanium catalysts have been used on the majority of SCR system installations. The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600 to 750° F. At temperatures above 850° F permanent damage to the vanadium/titanium catalyst occurs. For Unit 1, the flue gas temperature in the HRSG of the CTG/HRSG would typically range from 600° F to 800° F. Accordingly, a vanadium/ titanium catalyst can be installed for Unit 1. Therefore, the vanadium/titanium-based catalyst will be evaluated further for these units.

Because the SCR system requires the regulation of ammonia injection based on the NO_x emission monitors, the accuracy of the emission reading directly influences the amount of actual error in the ammonia injection rate. Therefore, erroneous emission readings can result in excess ammonia levels even when the actual NO_x value is below the permitted value. This may result in excessive ammonia "slip" being discharged to the atmosphere with little or no improvement in NO_x emissions. Reduction of the NO_x emission concentrations to levels below 2.0 ppmvd also raises concerns with the additional ammonia that may be emitted to obtain further reduced levels. Although SCR catalyst vendors have indicated that ammonia emissions will not be increased, these vendors are not solely responsible for guaranteeing ammonia slip. The distribution of the ammonia in the duct is the key parameter since localized maldistribution of the ammonia will cause the ammonia to pass through the catalyst without reacting with the NO_x. The proper distribution of the gas and ammonia is difficult to obtain when both reactants, NO_x and NH_3, are at such low concentrations. This distribution would be even more difficult, if not impossible, to maintain during transient operations, such as load changes, when flow patterns are changing. Changes in operation from one stable load to another stable load may present problems since the flow patterns and the loads may be different. Since the catalyst vendors are not responsible for the ammonia distribution, they typically limit their guarantees to some distribution level. Such conditions to reduce NO_x emissions to levels below 2.0 ppmvd that increase ammonia emissions will be counter productive to the reduction of overall emissions since ammonia presents an emission problem itself.

This SCR method of post-combustion control will be considered in this BACT analysis to control NO_x emissions.

4.2.7 NO_x Control Summary

This technology evaluation indicates that an SCR and a $SCONO_x$ system are the control technologies suitable for further evaluation beyond the use of good combustion practices, as provided by a DLN burner, and will be considered in this BACT analysis.

4.3 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increase the emissions of CO. Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions.

Carbon monoxide control methods may be divided into two categories: in-combustor CO formation control and post-combustion emission reduction. An in-combustor CO formation control process minimizes the quantity of CO formed in the combustion process. A post-combustion technology reduces the CO emissions in the flue gas stream after the CO has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of CO emissions required. The three different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Dry Low-NO_x (DLN) Burners.
- Post-Combustion Type:
  - Oxidation Catalyst.
  - $SCONO_x$.

The rationale behind whether the above technologies are evaluated as CO control for BACT is included in the following subsections.

4.3.1 Dry Low-NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state of the art DLN burners has reduced CO emissions as compared to those previously obtained by the use of water injection as the main NO_x control method. These improved combustion characteristics have allowed minimization of CO emissions without sacrificing NO_x control performance. For this reason, the use of low NO_x burners that use good combustion practices is the standard method of also controlling CO emissions.

4.3.2 CO Oxidation Catalyst

A current CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary and oxidizing catalysts, dependent on the uncontrolled emission level, are capable of reducing CO emissions from 80 to 90 percent. An 77.5 percent CO reduction rate (i.e. 8 ppm to 1.8 ppm)has been assumed for this BACT analysis.

4.3.3 $SCONO_x$

Another CO control technology that was previously discussed for NO_x control is the $SCONO_x$ process. The $SCONO_x$ system reduces CO emissions by oxidizing the CO to CO_2. The demonstrated application for this technology is currently limited to combined cycle combustion turbine units under 40 MW. The combustion turbine proposed for this project is approximately 170 MW, which is outside the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. However in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for CO control. Based on previous removal rates proposed by Goal Line, as with the CO Oxidation catalyst, 77.5 percent reduction rate has been assumed for this BACT analysis.

4.3.4 CO Control Technology Summary

This technology evaluation indicates that an oxidation catalyst and a $SCONO_x$ system are the control technologies suitable for further evaluation beyond the use of good combustion practices, as provided by a DLN burner, and will be considered in this BACT analysis.

4.4 Combined NO_x and CO Control Technology Summary

In-combustor NO_x and CO control by advanced combustion controls using dry low NO_x burners is the least stringent control technology considered for Unit 1. However, the use of a combination SCR/oxidation catalyst system or the $SCONO_x$ system are technologies capable of achieving significantly lower emissions than the application of dry low NO_x burners alone. Because the $SCONO_x$ system is capable of reducing NO_x and CO, emissions, the NO_x and CO BACT analyses have been combined to avoid double counting the $SCONO_x$ technology, thus inflating its economic impacts. The following control technologies will be evaluated in this BACT analysis and are ranked in order of relative control effectiveness:

- In-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions during natural gas firing for all operating loads for Unit 1 is considered the base case scenario. All modern combustion turbines of the type proposed for this Project include DLN combustors.

- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with duct burner to the level of 2.0 ppmvd and CO to 1.8 ppmvd emissions for the natural gas fired CTG/HRSG with duct burners.
- The addition of a $SCONO_x$ system to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with duct burner to the NO_x level of 2.0 ppmvd and CO emissions to 1.8 ppmvd.

The following evaluation considers energy, environmental, and economic impacts for the NO_x and CO combined technology scenarios evaluated. Table 4-1 outlines the expected NO_x and CO emissions rates from the evaluated emissions control alternatives of dry low NO_x burners (i.e. good combustion controls), SCR/CO catalyst, and $SCONO_x$. SCR/CO catalyst and $SCONO_x$ are considered the most stringent NO_x and CO emissions control alternatives as they achieve the lowest outlet emission rate. Therefore, if $SCONO_x$ is not found viable via energy, environmental, or economic impacts for the combined emissions reduction, the $SCONO_x$ technology will be eliminated from consideration, and a BACT evaluation would be done for control of NO_x and CO emissions separately.

4.5 NO_x and CO Combined Technology Energy, Environmental, and Economic Impacts Evaluation

The following section identifies the energy, environmental and economic impacts of the NO_x and CO combined control technologies.

4.5.1 $SCONO_x$ Energy Impacts

The use of a $SCONO_x$ system will increase the energy requirements on the system compared to use of dry low NO_x burners alone. The $SCONO_x$ system will increase the backpressure on the combustion turbine by about 4 inches water gauge (in. w.g.). This will reduce the output of Unit 1 by approximately 0.3 percent and increase the lost power generation. In addition, the period required for catalyst washing will result in increasing the lost power generation. Wahlco-Metroflex estimated the unit will be offline for a 24 hour period once per year to accommodate the washing process. Furthermore, there will be an energy loss due to steam consumption from the regeneration system. Steam is used as the carrier medium for the regeneration gas for the $SCONO_x$ system. Wahlco-Metroflex estimated that approximately 5,000 lb/h of steam would be used in the regeneration production. These three effects will be added together to determine the total lost power generation and are included in the annualized cost estimate. The $SCONO_x$ system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. Wahlco-Metroflex estimated that approximately 15 kW would be consumed during operation of the $SCONO_x$ system. This

Table 4-1
Estimated NO_x and CO Emissions from Alternate Control Technologies for Unit 1

	Control Technology Alternatives		
	LNB/Good Combustion Controls	SCR/CO Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	12.2	2.0	2.0
lb/h	100.6	16.5	16.5
tons per year (tpy)[a]	440.6	72.3	72.3
percent reduction	N/A	83.6%	83.6%
NO_x Emission Reduction (tpy)	Base	368.3	368.3
CO Emissions			
ppmvd (at 15 percent O_2)	8.0	1.8	1.8
lb/h	39.7	8.9	8.9
tons per year (tpy)[a]	173.9	39.1	39.1
percent reduction	N/A	77.5%	77.5%
CO Emission Reduction (tpy)	Base	134.8	134.8

[a]Total emissions are based on 8,760 hours per year firing natural gas at an ambient temperature of 73° F.

increase in power consumption will be included in the annualized cost estimate. The natural gas required for the production of the regeneration gas will increase the annualized cost associated with using the $SCONO_x$ system. The annualized cost of natural gas consumption is included in the annualized cost analysis.

4.5.2 $SCONO_x$ Environmental Impacts

The $SCONO_x$ catalyst is composed of precious metals coated with potassium carbonate. When the potassium carbonate coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. Although recycling the potassium carbonate is a positive aspect of this technology, the oxidation of CO and VOC that results from the application of this technology directly results in an increased production of CO_2, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of a $SCONO_x$ system would directly counter this initiative.

The $SCONO_x$ catalyst will oxidize approximately 1.0 percent of the SO_2 in the flue gas to SO_3. The SO_3 will then react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate matter will predominately consist of PM_{10}.

4.5.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of Unit 1. An SCR system requires an ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on the combustion turbine. The SCR system would add about 2.8 inches water gauge (in. w.g.) backpressure to the unit for the NO_x reduction to 2.0 ppmvd. This would reduce the output of Unit 1 by approximately 516 kW.

4.5.4 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes and is also regulated by USEPA's Chemical Accident Prevention Provisions. This BACT analysis is based on the use of aqueous ammonia that can be stored and used more safely than anhydrous ammonia. According to the Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

Some ammonia slip from the Combustion Turbine Unit 1 stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Ammonia slip from an SCR system is one of the major design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictate associated catalyst replacement. Exceeding the NESCAUM's recommendation, FDEP recently proposed an ammonia slip of 5 ppmvd for Turkey Point, a combined cycle combustion turbine unit utilizing SCR. Based on the recent Turkey Point air permit, an ammonia slip design value of 5 ppmvd at 15 percent O_2 is used for this analysis.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600° F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than PM_{10}. As the catalyst gradually deactivates, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip for a given level of performance. Increased ammonia slip in turn results in additional ammonia salt formation which could result in increased opacity and particulate emissions from Unit 1.

4.5.5 Oxidation Catalyst Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. The additional backpressure of about 1.2 inches, water gauge, will reduce the combustion turbine output by approximately 221 kW. The cost of lost power revenue due to the backpressure is included in the economic analysis.

4.5.6 Oxidation Catalyst Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions is that a percentage of the SO_2 in the flue gas will oxidize to SO_3. The higher the operating temperature, the higher the SO_2 to SO_3 oxidation potential. It is estimated that approximately 20 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid mist (H_2SO_4). The increase in H_2SO_4 emissions would increase PM_{10} emissions.

Spent oxidation catalyst is made up of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of the precious metal content of the catalyst, the oxidation catalyst can also be recycled to recover the precious metals.

As mentioned previously, the installation of an oxidation catalyst will also increase the backpressure on the turbine, thereby decreasing efficiency. This decrease in efficiency will lead to increased emissions of all pollutants on a unit power output basis. The oxidation of CO also directly results in increased production of CO_2, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO_2 because of its contribution to global climate change. Installation of an oxidation catalyst would directly counter this initiative.

4.5.7 Economic Impacts for SCR (2.0 ppmvd)/Oxidation Catalyst Versus $SCONO_x$

The use of an SCR/oxidation catalyst or $SCONO_x$ has significant economic impacts to Unit 1. An analysis of the economic impact is provided in this section.

4.5.7.1 Capital Costs for SCR (2.0 ppmvd)/Oxidation Catalyst and $SCONO_x$.

Table 4-2 presents the capital costs for installing an SCR/oxidation catalyst and $SCONO_x$

Table 4-2
NO_x/CO Combined Control Alternative Capital Cost For Unit 1

	DLN	$SCONO_x$	SCR/OX Cat	Remarks
Direct Capital Cost				Cost based on emissions in Table 4-1
Catalysts	N/A	Included	1,436,000	Estimated from NE Corporation
Catalyst Reactor Housing	N/A	Included	604,000	Estimated from previous projects
$SCONO_x$ System	N/A	7,800,000	0	Vendor Estimate
Control/Instrumentation	N/A	180,000	180,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Injection/Dilution)	N/A	N/A	420,000	Estimated from Peerless Mfg. Co and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**7,980,000**	**2,640,000**	
Sales Tax		0	0	Not applicable to FMPA
Freight	N/A	798,000	264,000	10% of PEC
Balance of Plant	N/A	2,394,000	792,000	30% of PEC. See text for background information on this item
Total Direct Cost (DC)	**N/A**	**11,172,000**	**3,696,000**	
Indirect Capital Costs				
Contingency	N/A	1,117,000	370,000	10% of DC
Engineering and Supervision	N/A	1,117,000	370,000	10% of DC for $SCONO_x$. 10% of DC for SCR and 10% of DC for CO catalyst.
Construction & Field Expense	N/A	559,000	185,000	5% of DC
Construction Fee	N/A	1,117,000	370,000	10% of DC
Start-up Assistance	N/A	223,000	74,000	2% of DC
Performance Test	N/A	50,000	50,000	Assumed $50,000 emission test.
Total Indirect Capital Costs (IC)	**Base**	**4,183,000**	**1,419,000**	
Installed Costs (DC+IC)	**Base**	**15,355,000**	**5,115,000**	
Less Catalyst	Base	4,800,000	1,436,000	Catalyst is viewed as an O&M value.
Total Capital Investment (TCI)	**Base**	**10,555,000**	**3,679,000**	TCI = DC + IC – Catalyst

system on Unit 1 during natural gas firing to achieve a NO_x outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 1.8 ppmvd. The cost of the SCR/oxidation catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation and freight. The catalyst costs were not included in the total capital investment (TCI) cost but assessed as an annual cost. The cost of the $SCONO_x$ system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, and freight. The BOP cost for the SCR/oxidation catalyst and $SCONO_x$ system consist of 8 percent of the purchased equipment costs (PEC) for foundation and supports, 14 percent for handling and erection, 4 percent for electrical installation, 2 percent for piping, 1 percent for insulation, and 1 percent for painting. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates.

Quotations for the SCR and oxidation catalyst material were based on vanadium/titanium and precious metal type catalysts, respectively. The direct installation costs included the balance of plant items such as foundations, insulation and lagging and painting and were calculated as percentages of the total purchased equipment costs. The total capital investment was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR/Oxidation Catalyst systems are percentages of the total direct costs (DC) and are site specific. The indirect capital costs for the $SCONO_x$ system are percentages of the $SCONO_x$ system DC.

There are many potential items and uncertainties that are not captured by the cost items included in the estimate, such as possible changes between cost quotes and contract values, changes in operating conditions, process contingency, increased equipment cost, scope changes, labor/wage increases, and schedule acceleration. In addition, the Electric Power Research Institute published the document titled, NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook in November 1991 and list under NO_x control cost (Page 5-5) the following text:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3% of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50% of the sum of direct and indirect costs.[1] A contingency factor of 20% of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and

[1]U.S. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations: Volume I, EPA 600/8-79-018a, June 1979.

> small boilers and municipal waste combustors.[2,3]. Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

Therefore a 10 percent contingency factor has been assumed for this project.

Based on the analysis in this section, the total capital investment for the SCR/oxidation catalyst control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital investment for Unit 1 controlling NO_x and CO to 2.0 ppmvd and 1.8 ppmvd, respectively is estimated to be $3,679,000.

The total capital investment for the $SCONO_x$ control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital investment for Unit 1 controlling NO_x and CO to 2.0 ppmvd and 1.8 ppmvd respectively is estimated to be $10,555,000.

4.5.7.2 Operating Costs for SCR/Oxidation Catalyst Versus $SCONO_x$. Table 4-3 presents the annualized operating costs using a SCR/oxidation catalyst and $SCONO_x$ system to achieve NO_x outlet emissions of 2.0 ppmvd and CO emissions of 1.8 ppmvd while firing natural gas for Unit 1. Annualized operating costs for the SCR/oxidation catalyst include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements for both the SCR and the oxidation catalyst will require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions will increase. At the point ammonia slip approaches 5 ppmvd the catalyst must be replaced. The oxidation catalyst will degrade from normal operation that will be evident by an increase in CO emissions, thereby requiring replacement of the oxidation catalyst. Currently, SCR and oxidation catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours.

Ammonia consumption rates were based on a stoichiometric ratio of 1.05 for reacting NO_x. The heat rate penalty cost (lost power generation) item reflects the cost due to the SCR and oxidation catalyst backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annualized cost estimate.

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[2]U.S. Environmental Protection Agency, Industrial Boiler SO_2 Cost Report, EPA 450/3-85-011, November 1984.

[3]U.S. Environmental Protection Agency, Municipal Waste Combustors – Background Information for Proposed Standards: Control of NO_x Emissions, EPA 450/3-89-27d, August 1989.

The use of either an SCR/oxidation catalyst system or a $SCONO_x$ system increases the energy requirements of the project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. $SCONO_x$ consumes power to open and close the catalyst dampers and to produce the regenerating gas. The maintenance costs will consist of routine system maintenance for each system. However, there is an additional annual maintenance cost for washing the $SCONO_x$/$SCOSO_x$ catalyst. Therefore, the $SCONO_x$ system will include the additional O&M cost for catalyst washing.

The indirect annual costs include capital recovery, overhead, administrative charges and insurance. The overhead annual cost is estimated to be 60 percent of the O&M costs. According to the OAQPS Cost Manual there are two types of overhead, payroll and plant. Payroll overhead expenses include workmen's compensation, social security, vacations, group insurance and other fringe benefits. Plant overhead is not tied into O&M of the control system, but is related to plant protection, control labs, employee amenities, plant lighting, parking areas, and landscaping. The OAQPS Cost Manual allows one to combine these overhead cost into one sum. The administrative cost covers sales, research and development, accounting, and other home office expenses. The insurance cost was based on 1 percent of the total capital investment for each system.

4.5.7.3 Total Annualized Costs for SCR (2 ppmvd)/Oxidation Catalyst Versus $SCONO_x$. Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Table 4-3 shows the total annualized cost for a SCR/Oxidation Catalyst system for Unit 1 is estimated to be $1,765,000, which is less than a third of the cost of a SCONOX system having a total annualized cost of $5,355,000.

4.5.7.4 Conclusions. Based on the fact that the SCR/oxidation catalyst system is a lower capital cost system and has lower annualized costs than the $SCONO_x$ system, the SCONOx system will not be further evaluated as part of the BACT analysis. The remainder of the BACT analysis will concentrate on evaluating technologies for the control of each pollutant separately.

4.6 NO_x Only Energy, Environmental, and Economic Impacts Evaluation

The following section identifies economic impacts of the NO_x only BACT analysis. This section will not include a discussion of energy and environmental impacts, as they are the same as those discussed in the combined control BACT evaluation for NO_x and CO as listed in Section 4.5.

Table 4-3
NO_x/CO Combined Control Alternative Annualized Cost For Unit 1

	DLN	SCONOx	SCR/OX Cat	Remarks
Direct Annual Cost				Cost based on emissions in Table 4-1
Catalyst Replacement	N/A	1,414,000	660,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life for SCR/OX cat and 5 year catalyst life for SCONOx.
Operation and Maintenance	N/A	38,000	22,000	See text for background information on this item
Maintenance Materials	N/A	23,000	11,000	
Reagent Feed	N/A	N/A	103,000	Assumes 1.05 stoichiometric ratio
Natural Gas Consumption	N/A	44,000	0	
Power Consumption	N/A	113,000	10,000	Includes injection blower and vaporization of ammonia
Lost Power Generation	N/A	2,187,000	417,000	Back pressure on combustion turbine. Includes seven days of lost power generation time for catalyst/system cleaning for SCONOX
Annual Distribution Check	N/A	56,000	28,000	Estimated as 0.5% of the total direct cost for SCONOX and 1% for SCR
Total Direct Annual Cost	**N/A**	**3,875,000**	**1,252,000**	
Indirect Annual Costs				
Overhead	N/A	23,000	13,000	60% of O&M Cost
Administrative Charges	N/A	307,000	102,000	2% of Installed Cost
Property Taxes	N/A	0	0	Not included
Insurance	N/A	154,000	51,000	1% of Installed Cost
Capital Recovery	N/A	996,000	347,000	Capital Recovery Excluding Catalyst
Total Indirect Annual Costs	**N/A**	**1,480,000**	**513,000**	
Total Annualized Cost	**N/A**	**5,355,000**	**1,765,000**	

4.6.1 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of a SCR to Unit 1 without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emission controls a separate economic analysis is required. An analysis of the economic impact of SCR as a separate control technology for NO_x emissions of 2.0 ppmvd is provided in this section. The BACT costs presented in this analysis are based on operating the combustion turbine, with duct firing, at 100 percent of base load for 8,760 hours per year on natural gas.

4.6.2 Economic Impacts for SCR (2.0 ppmvd NO_x) System

The use of an SCR has significant economic impacts to the TCEC Project. The application of SCR on Unit 1 must incorporate special design and operational/maintenance criteria, such as periodic catalyst replacements and increased associated plant outage costs. A detailed description of the economic impacts of SCR was provided previously in Subsection 4.5.7 and will not be repeated.

4.6.2.1 Capital Costs for SCR (2.0 ppmvd NO_x). Table 4-4 summarizes the economic capital cost for implementing SCR on Unit 1. Based on the analysis in this section, the total installed capital costs for the SCR control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital investment cost of SCR for Unit 1 controlling NO_x to 2.0 ppmvd is estimated to be $2,996,000.

4.6.2.2 Total Annualized Costs for SCR (2.0 ppmvd NO_x). Total annualized costs for the SCR control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Table 4-5 shows the total annualized cost for an SCR system is estimated to be $1,306,000. This annualized cost for the Unit 1 SCR system results in a cost effectiveness of approximately $3,546 per ton of NO_x removed.

4.6.3 Conclusions

To summarize the information discussed in this section, SCR is considered a cost effective technology for control of emissions on Unit 1.

Table 4-4
NO_x Emission Control Alternative Capital Cost for Unit 1

	DLN	SCR	Remarks
Direct Capital Cost			Cost based on emissions in Table 4-1.
Catalyst	N/A	928,000	Estimated from NE Corporation
Catalyst Reactor Housing	N/A	544,000	
Control/Instrumentation	N/A	140,000	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	N/A	420,000	
Purchased Equipment Costs (PEC)	N/A	**2,032,000**	
Sales Tax		0	Not applicable to FMPA.
Freight	N/A	203,000	10% of PEC
Balance of Plant	N/A	610,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**2,845,000**	
Indirect Capital Costs			
Contingency	N/A	285,000	10% of DC
Engineering and Supervision	N/A	285,000	10% of DC
Construction & Field Expense	N/A	142,000	5% of DC
Construction Fee	N/A	285,000	10% of DC
Start-up Assistance	N/A	57,000	2% of DC
Performance Test	N/A	25,000	Assumed $25,000
Total Indirect Capital Costs (IC)	**Base**	**1,079,000**	
Installed Costs (DC + IC)		**3,924,000**	
Less SCR Catalyst Cost		928,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**Base**	**2,996,000**	

Table 4-5
NOx Emissions Control Annualized Cost for Unit 1

	DLN	SCR	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1
Catalyst Replacement	N/A	427,000	Includes freight, installation, and 3-yr capital recovery factor based on 3 yr. guaranteed catalyst life
Operation and Maintenance	N/A	22,000	See text for background information
Maintenance Materials	N/A	11,000	See text for background information
Reagent Feed	N/A	103,000	Assumes 1.05 stoichiometric ratio
Power Consumption	N/A	10,000	Includes injection blowers and vaporization of ammonia
Lost Power Generation	N/A	292,000	Back pressure on combustion turbine
Annual Distribution Check	N/A	28,000	Estimated as 1 % of the total direct cost
Total Direct Annual Cost	N/A	893,000	
Indirect Annual Costs	N/A		
Overhead	N/A	13,000	60% of Operation and Maintenance cost
Administrative Charges	N/A	78,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	39,000	1% of Installed Costs
Capital Recovery	N/A	283,000	Capital recovery excluding catalyst
Total Indirect Annual Cost	N/A	413,000	
Total Annualized Cost	N/A	1,306,000	
NO_x Annual Emissions, tpy	440.6	72.3	Emission taken from Table 4-1
NO_x Emissions Reduction, tpy	N/A	368.3	Emissions calculated in Table 4-1
NO_x Total Cost Effectiveness, $/ton	N/A	3,546	Total Analyzed Cost/Emissions Reduction

4.7 CO Only Energy, Environmental, and Economic Impacts Evaluation

The following section identifies economic impacts of the CO only BACT analysis. This section will not include discussion of energy and environmental impacts, as they are the same as listed in the combined control BACT evaluation for NO_x and CO as listed in Section 4.5.

4.7.1 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the TCEC Project. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating each combustion turbine, with duct firing, at 100 percent of base load for 8,760 hours per year on natural gas. The oxidation catalyst is used to reduce CO emissions.

4.7.2 Capital Cost for Oxidation Catalyst

Table 4-6 presents the capital costs for installing an oxidation catalyst on the units during natural gas firing to achieve a CO outlet emission level of 1.8. The capital costs for the systems includes the oxidation catalyst, oxidation catalyst reactor housing, controls and instrumentation, sales taxes and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items such as foundations, insulation and lagging, and painting, and were calculated as percentages of the total purchased equipment costs (PEC). The total capital investment was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR/Oxidation Catalyst systems are percentages of the total direct cost (DC) and are site specific. The three percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating, as discussed in Section 4.5.7.1.

Total capital costs for the oxidation catalyst control system to reduce CO is calculated as the sum of the direct and indirect installed costs. The total capital investment per unit for an oxidation catalyst system to reduce CO emissions from Unit 1 is estimated to be $683,000.

4.7.3 Operating Costs for Oxidation Catalyst

Table 4-7 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve a 77.5 percent reduction in CO emissions while firing natural gas on Unit 1. Annualized operating costs for the system includes catalyst

Table 4-6
CO Reduction System Capital Cost For Unit 1

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Capital Cost			Cost based on emissions in Tables 4-1.
Oxidation Catalyst	N/A	508,000	Estimated from NE Corporation
Catalyst Reactor Housing	N/A	60,000	
Control/Instrumentation	N/A	40,000	Estimated; includes controls and monitoring equipment.
Purchased Equipment Costs (PEC)	N/A	608,000	
Sales Tax	N/A	0	Not applicable to FMPA
Freight	N/A	61,000	10% of PEC
Balance of Plant	N/A	182,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**851,000**	
Indirect Capital Costs	N/A		
Contingency	N/A	85,000	10% of DC
Engineering and Supervision	N/A	85,000	10% of DC
Construction & Field Expense	N/A	43,000	5% of DC
Construction Fee	N/A	85,000	10% of DC
Start-up Assistance	N/A	17,000	2% of DC
Performance Test	N/A	25,000	Assumed value of $25,000
Total Indirect Capital Costs (IC)	**Base**	**340,000**	
Installed Costs (DC +IC)		**1,191,000**	
Less Catalyst	N/A	508,000	Catalyst is viewed as an O&M Value.
Total Capital Investment, TCI	**Base**	**683,000**	

Table 4-7
CO Control Annualized Cost For Unit 1

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1.
Catalyst Replacement	N/A	234,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life.
Operation and Maintenance	N/A	0	Not applicable for Oxidation Catalyst
Lost Power Generation		125,000	Back pressure on combustion turbine
Total Direct Annual Cost	**N/A**	**359,000**	
Indirect Annual Costs			
Overhead	N/A	0	Not Applicable because of zero O&M
Administrative Charges	N/A	24,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	12,000	1% of Installed Costs
Capital Recovery	N/A	64,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**N/A**	**100,000**	
Total Annualized Cost	**Base**	**459,000**	
CO Annual Emissions, tpy	173.9	39.1	Emissions taken from Table 4-1.
CO Emissions Reduction, tpy	N/A	134.8	Emissions taken from Table 4-1.
CO Total Cost Effectiveness, $/ton	**N/A**	**3,405**	**Total Annualized Cost/Emissions Reduction**

replacement and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee an oxidation catalyst life of three years of equivalent operating hours for an oxidation catalyst.

4.7.4 Total Annualized Costs for Oxidation Catalyst

Total annualized costs for the oxidation control system is calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total installed costs. The total annualized cost for a 1.8 ppmvd CO oxidation catalyst system for Unit 1 is estimated to be $459,000. This annualized cost for Unit 1 results in a cost effectiveness of approximately $3,405 per ton of CO removed.

4.7.5 Conclusions

Based on the high cost effectiveness value for the CO catalyst it is determined that add-on controls to further reduce CO emissions are unwarranted given the low CO emission characteristics of Unit 1 firing natural gas as the primary fuel. BACT for CO emissions control for Combustion Turbine Unit 1 is Dry Low NO_x burners with good combustion control.

5.0 Unit 1 PM/PM_{10} BACT Analysis

The objective of this analysis was to determine BACT for PM/PM_{10} emissions from Unit 1. This includes the combustion turbine and supplemental firing from duct burners in the HRSG as a total unit.

PM/PM_{10} emissions from the combustion turbine are a result of incomplete combustion and trace particulate parameters in the fuel. The emissions of particulate matter from Unit 1 will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for combustion turbines do not establish a particulate emission limit. Natural gas contains only trace quantities of non-combustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations as referenced by the State of Florida, such as the FPL Turkey Point, FPL Martin, FPL Manatee, FPL Fort Myers, Santa Rosa and the City of Tallahassee projects, the use of combustion controls and natural gas (low sulfur fuel) is considered BACT for particulate matter and is proposed for Unit 1. Ultra-low sulfur fuel oil will only be used as a backup fuel. Limited operation while firing ultra-low sulfur fuel oil in the combustion turbine is considered BACT

6.0 Unit 1 SO_2 BACT Analysis

The objective of this analysis was to determine BACT for SO_2 emissions from Unit 1. The SO_2 emissions are based on operating the combustion turbine with duct firing at 100 percent of base load for a total of 8,760 hours while firing natural gas.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. The selection of natural gas fuel provides inherently low SO_2 emissions.

Emissions of SO_2 can be controlled by limiting sulfur content in the fuel, limiting fuel oil usage, or by a post-combustion flue gas desulfurization (FGD) system. The fuel for this project is natural gas with a maximum expected sulfur content of 2.0 grains per 100 standard cubic feet. In addition, when the unit is firing fuel oil, the unit will fire ultra-low sulfur fuel oil which has a sulfur content of 0.0015 percent sulfur by weight.

To date, no supplemental SO_2 emission controls, such as flue gas desulfurization system (FGD) systems have been imposed on combined cycle combustion turbines. Such a system would be both technically and economically prohibitive.

Therefore, BACT for Unit 1 is the use of natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight. Basis of this determination is firing natural gas up to a maximum of 8,760 hours per year as the primary fuel and firing ultra-low sulfur fuel oil a maximum of 500 hours per calendar year as a backup fuel.

7.0 Unit 1 H_2SO_4 BACT Analysis

The objective of this analysis was to determine BACT for sulfuric acid mist (H_2SO_4) emissions from Unit 1. The H_2SO_4 emissions are based on operating the combustion turbine with duct firing at 100 percent of base load for a total of 8,760 hours while firing natural gas.

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The natural gas (primary fuel) and ultra-low sulfur fuel oil to be utilized for Unit 1 will contain less than 2 grains per 100 standard cubic feet and 0.0015 percent sulfur by weight, respectively. The selection of low sulfur fuel (both natural gas and ultra-low sulfur fuel oil) provides inherently low SO_2 emissions, thus controlling the formation of sulfuric acid mist. In addition, no supplemental SO_3 emission controls, such as FGD systems or H_2SO_4 abatement systems, have been imposed on natural gas fired or low sulfur fuel oil fired combustion turbines by regulatory agencies.

Therefore, BACT for Unit 1 is the use of good combustion controls while firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight. The basis of this determination is firing natural gas up to a maximum of 8,760 hours as the primary fuel and firing ultra-low sulfur fuel oil a maximum of 500 hours as a backup fuel per calendar year.

8.0 Conclusions

The following is a summary of the proposed BACT determinations and associated emission rates for Unit 1 to be installed at the Treasure Coast Energy Center for FMPA. Unit 1 will fire natural gas as the primary fuel and ultra-low sulfur fuel oil as the backup fuel. Emissions and conclusions for the BACT analysis are based on Unit 1 operating a maximum of 8,760 natural gas hours per year at an average ambient temperature of 73° F. Firing on ultra-low sulfur fuel oil is based upon a maximum 500 hours per year of operation.

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of selective catalytic reduction to achieve 2 ppmvd at 15 percent O_2 while firing natural gas and 8 ppmvd at 15 percent O_2 while firing ultra-low sulfur fuel oil in accordance with the defined operating hours for each fuel.
- Carbon monoxide (CO) emissions--BACT was determined to be the use of good combustion controls while firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight in accordance with the defined operating hours for each fuel.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight in accordance with defined operating hours for each fuel.
- Volatile Organic Compounds (VOC) emissions--The emissions of VOCs will be less than the major source PSD threshold level. Therefore a BACT analysis for VOCs is not required for Unit 1.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight in accordance with the defined operating hours for each fuel.
- Sulfur acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls while firing natural gas or ultra-low sulfur fuel oil with less than 0.0015 percent sulfur by weight in accordance with the defined operating hours for each fuel.

9.0 Unit 1 Auxiliary Boiler

Unit 1 will utilize a 7.2 MBtu/h package boiler for supplemental steam supply for startup operations of the Unit 1 combined cycle system. The auxiliary boiler will fire only natural gas which results in minimal emissions. Due to the size of the Unit 1 auxiliary boiler, post combustion emissions controls for NO_x such as SCR or SNCR, emissions controls for SO_2 such as flue gas desulfurization systems, or emission controls for CO such as oxidation catalyst have not been employed or required. Therefore, the proposed BACT for the Unit 1 Auxiliary Boiler is good combustion controls while firing natural gas.

10.0 Unit 1 Safe Shutdown Diesel Generator

A review of the RBLC indicates that this type of emergency equipment has not been required to install additional NO_X controls because of intermittent operation. The remaining pollutants are controlled by good combustion controls. Due to the size of the safe shutdown diesel generator and the fact that this is emergency equipment, post combustion emissions controls for NO_x such as SCR or SNCR, emissions controls for SO_2 such as flue gas desulfurization systems, or emission controls for CO such as oxidation catalyst are not considered BACT. Therefore, the proposed BACT for the safe shutdown diesel generator is good combustion controls while firing ultra low sulfur distillate oil. The proposed BACT has no adverse environmental or energy impacts.

11.0 Unit 1 Mechanical Draft Cooling Tower

Heat rejection needs (i.e. cooling) will be accomplished by the use of a mechanical draft cooling tower with multiple cells. The mechanical draft cooling tower will be an induced draft cooling tower system in which the cooling fans are located downstream of the tower fill.

The only emissions expected from the mechanical draft cooling tower is PM and PM_{10} in the form of cooling tower drift. Cooling tower drift is dissolved solids contained in droplets of the cooling water that escape past the drift eliminators. The design of the cooling towers and drift eliminators will be to maintain a drift rate less than 0.0005 percent of the circulating water flow rate. The drift rate expected, based on the design of the Unit 1 Mechanical Draft Cooling Tower, is consistent with recently permitted combined cycle combustion turbine plants such as FPL Turkey Point and is the proposed BACT for Unit 1. The proposed BACT has no adverse environmental or energy impacts.

12.0 Unit 1 Emergency Diesel Engine Fire Pump

The uncontrolled emissions for the emergency diesel fire pump is based on engine design and is proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install any additional emissions controls because the fire pump will operate only during tests to ensure operability and during times of emergency. The typical emissions from the emergency diesel engine fire pump are controlled by good combustion controls. The proposed BACT has no adverse environmental or energy impacts.

Appendix A
NO_x/CO Control Technology Review for Unit 1

Table A-1
NO_x BACT Clearinghouse Review List

Facility	State	Permit Date	Process	Output	Emission limit, ppmvd @ 15% O_2	Control Technology
FPL Bellingham	MA	AUG-99	Turbine, Combined Cycle, Natural Gas	~545 MW	1.5 (1 hour - 90% of time) 1.5-2.0 (10% of time)	SCR
Federal Cold Storage Cogeneration	CA	DEC-96	GE LM2500-M-2	222 MBtu/h	2.0	Water Injection, SCONOx
Sithe Mystic	MA	JAN-01	Turbine, Combined Cycle, Natural Gas	~775 MW	2.0	SCR
Duke Energy Arlington Valley	AZ	NOV-03	Turbine, Combined Cycle, Natural Gas	600 MW	2.0	SCR
Duke Morro	CA	NOV-00	Turbine, Combined Cycle, Natural Gas	1200	2	SCR
PDC El Paso Milford LLC	CT	APR-99	ABB GT-24 w/chillers (x 2)	~180 MW	2.0	SCR
FPL Turkey Point	FL	FEB-05	Combined Cycle	1,150 MW	2.0	SCR
ANP Bellingham Energy Company	MA	AUG-99	Combined Cycle	580 MW	2.0	SCR
Reliant Energy Hope	RI	MAY-00	Combined Cycle	4,624 MBtu/h	2.0	SCR
Goldendale Energy Inc.	WA	FEB-01	Combined Cycle	248.7 MW	2.0	SCR
Calpine OEC	PA	NOV-00	Combined Cycle	~550 MW	2.0 NG (3 hour) 2.5 NG (1 hour)	SCR
Cogen Tech, NJ	NJ	DEC-99	Combined Cycle	181MW	2.5 (1 hour)	SCR
Sutter Power Plant	CA	APR-99	SW 501F	170 MW	2.5	Dry low NOx, SCR
El Paso Belle Glade Energy Center	FL	SEP-01	Combined Cycle	600 MW	2.5	Dry low NOx, SCR
La Paloma Generating Co.LLC	CA	MAY-99	ABB Model GT-24	262 MW	2.5	Dry-low NOx, SCR
El Paso Manatee	FL	APR-02	Combined Cycle	600	2.5 (24 hour) NG	Dry-low NOx, SCR
FPL Manatee	FL	APR-03	Combined Cycle	1150	2.5 (24 hour) NG	Dry-low NOx, SCR
FPL Martin	FL	APR-03	Combined Cycle	1150	2.5 (24 hour) NG 12-FO	Dry-low NOx, SCR

Table A-1 (Continued)
NO_x BACT Clearinghouse Review List

Facility	State	Permit Date	Process	Output	Emission limit, ppmvd @ 15% O_2	Control Technology
PGN Hines III	FL	SEP-03	Combined Cycle	530	2.5 (24 hour) NG 10-FO	Dry-low NOx, SCR
Turlock Irrigation District	CA	AUG-94	GE LM5000	417 MBtu/h	3.0	SCR, Steam Injection
Sacramento Power Authority (Campbell Soup)	CA	AUG-94	Siemens V84.2	1,257 MBtu/h	3.0	Water injection, SCR
Choctow County, LLC	MS	NOV-03	Turbine, Natural Gas Fired	230 MW each Turbine	3.5	SCR
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas	170 MW	3.5	SCR
Granite Road Limited	CA	MAY-91	Turbine, Gas	460.9 MBtu/h	3.5	SCR, Steam Injection
Enron/Ft. Pierce	FL	AUG-01	Turbine, Combined Cycle, Natural Gas	~250 MW	3.5 NG (3 hour) 10 FO	SCR

Table A-2
CO BACT Clearinghouse Review List

Facility	State	Permit Date	Process	Output, MW	Emission limit ppmvd @ 15% O_2 or as indicated	Control Technology
Newark Bay Cogeneration Partnership, L.P.	NJ	JUN-93	Turbines, Combustion Natural Gas Fired	137	1.8	Oxidation Catalyst
Longview Energy Development	WA	AUG-01	Combine Cycle	290	2.0	Oxidation Catalyst
FPL Bellingham	MA	AUG-99	Turbine, Combined Cycle, Natural Gas	~545 MW	2.0	Oxidation Catalyst
Sithe Mystic	CA	JAN-01	Turbine, Combined Cycle, Natural Gas	~775 MW	2.0	Oxidation Catalyst
Cogen Tech, NJ	NJ	DEC-99	Cogeneration	181MW	2.0 (1 hour)	Oxidation Catalyst
Duke Morro	CA	NOV-03	Turbine, Combined Cycle, Natural Gas	1200	2	Oxidation Catalyst
El Paso Manatee	FL	APR-03	Combined Cycle	1150	2.5 (3 hour) NG 4 (3 hour, PA) NG	Oxidation Catalyst
Saranac Energy Company	NY	JUL-92	Turbines, Combustion Natural Gas Fired	1123	3	Oxidation Catalyst
Blue Mountain Power, L.P	PA	JUL-96	Combustion Turbine with Heat Recovery Boiler	153	3.1	Oxidation Catalyst
Enron/Ft. Pierce	FL	AUG-01	Turbine, Combined Cycle, Natural Gas	~250 MW	3.5 NG (3 hour) 10 Low Load 8-FO	Oxidation Catalyst
Sutter Power Plant	CA	APR-99	Turbine, SW 501F	170	4	Oxidation Catalyst
Brooklyn Navy Yard Cogeneration Partners, L.P	NY	JUN-95	Turbine, Natural Gas Fired	240	4	No Control
FPL Turkey Point	FL	FEB-05	Combined Cycle	1,150 MW	4.1 NG (DB Off) 7.6 NG (DB On) 14.1 NG (DB +PA) 8.0 FO	Good Combustion Control

Table A-2 (Continued)
CO BACT Clearinghouse Review List

Facility	State	Permit Date	Process	Output, MW	Emission limit ppmvd @ 15% O_2 or as indicated	Control Technology
Crockett Cogeneration (C&H Sugar)	CA	OCT-93	GE PG7221 (FA)	240	5.9	Good Combustion Control
FPL Manatee	FL	APR-03	Combined Cycle	1150	8 -NG(DB off) 10 -NG(DB, PA)	Good Combustion Control
FPL Martin	FL	APR-03	Combined Cycle	1150	7.4 -NG (New, Clean) 8 -NG(DB off) 10 -NG(DB, PA)	Good Combustion Control
Calpine OEC	PA	NOV-00	Combined Cycle	~550 MW	10 NG(1 hour)	Good Combustion Control
PGN Hines III	FL	SEP-03	Combined Cycle	530	10 NG(1 hour) 20-FO	Good Combustion Control
Milford Power	CT	APR-99	ABB GT-24	~550 MW	13-52 lb/h	Oxidation Catalyst
Mobile Energy, LLC - Hog Bayou	AL	JAN-99	GE 7FA	170	0.04 lb/MBtu	Good Combustion Control
Alabama Power, Plant Barry	AL	AUG-98	GE 7FA	170	0.057 lb/MBtu	Good Combustion Control
Alabama Power, Plant Barry	AL	AUG-99	GE 7FA	170	0.06 lb/MBtu	Good Combustion Control
Alabama Power Theodore Cogeneration Facility	AL	MAR-99	GE 7FA	170	0.086 lb/MBtu	No Control

State	Facility	# of New MW	Final Permit Issued	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Region 4													
AL	Alabama Power - Olin Cogeneration	137	12/01/1997	1	1	GE 7EA (80 MW)	NG	CC	8,760	15 ppm	DLN		Power Augmentation
AL	Alabama Power - GE Plastics Cogeneration	100	05/01/1998	1	1	GE 7EA (80 MW)	NG	CC	8,760	9 ppm; 0.20 lb/MMBtu (DB)	DLN		
AL	Alabama Power, Plant Barry	800	08/01/1998	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
AL	Alabama Power, Plant Barry	200	08/01/1999	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
AL	Mobile Energy, LLC - Hog Bayou	200	1-99	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR; WI		
AL	Alabama Power - Theodore Cogeneration Facility	210	3-99	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
AL	Tenaska Alabama Partners	846	11-99	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
AL	Georgia Power - Goat Rock	-	4-00	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
AL	Georgia Power - Goat Rock (revision of above PSD application)	2,460	4-01	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
AL	Alabama Electric Cooperative - Gantt Plant	500	3-00	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
AL	South Eastern Energy Corp.	1,500	1-01	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
AL	Calpine Solutia - Decatur	700	6-00	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
AL	Calpine BP Amoco	700	6-00	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
AL	Tenaska Alabama II Generating Station	900	2-01	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu NG/FO - Mit	SCR/WI		
AL	Hillabee Energy Center	700	1-01	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
AL	Duke Energy - Alexander City	1,260	2-01	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
AL	GenPower - Kelly, LLC	1,260	1-01	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
AL	Blount County Energy	800	1-01	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
AL	Alabama Power - Autaugaville	1,260	1-01	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
AL	Tenaska Alabama IV Partners	1,840	10/09/2001	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - $6,145/ton NOX; CatOx- $1,506/ton CO
AL	Duke Energy Autauga, LLC	630	10/29/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $18760/ton NOX; CatOx- $5,006/ton CO

AL	Duke Energy Dale, LLC	630	12/17/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmbtu)	SCR		SCONOx - $18,403/ton NOX; CatOx- $2,634/ton CO+VOC
AL	Barton Shoals Energy, LLC	1,200	07/15/2002	4	4	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm (0.0092 lb/mmbtu)	SCR		EPA did not received application until 5/24/02
FL	City of Lakeland, McIntosh Power Plant	250	7-10-98	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm until 5/2002, 9 ppm after, 7.5 ppm if CC. NG; 42 ppm or 15 ppm FO	DLN or SCR; WI or SCR		Power Augmentation
FL	Santa Rosa Energy Center, Sterling Fibers Mfg. Facility	241	12-4-98	1	1	GE 7FA (167 MW)	NG	CC	8,760	9 ppm, 9.8 ppm w/ DB	DLN		If a different CT is used, SCR may be required to meet 6 ppm NOx)
FL	Kissimmee Utility Authority, Cane Island Power Park -Unit 3	250	draft permit	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
FL	Duke Energy - New Smyrna Beach	500	draft permit	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
FL	City of Tallahassee - Purdom	250	5-98	1	0	GE 7FA (160 MW)	NG; FO	CC	8,760	12 ppm NG; 42 ppm FO	DLN; WI	30-day	
FL	Gulf Power - Smith Station	340	7-00	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NOx and CO; SA = steam augmentation
FL	Florida Power & Light - Sanford	2,200	9-99	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
FL	Gainesville Regional Utilities, Kelly Generating Station	133	2-00	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NOx
FL	Calpine Osprey Energy Center	527	07/05/2001	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode
FL	Hines Energy (FPC)	530	06/07/2001	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOx - $16,712/ton NOx.; CatOx - $2,130/ton CO
FL	CPV - Gulfcoast	250	2-01	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOx - no cost eval.; CatOx - $4,350/ton CO
FL	TECO Gannon/Bayside	1,728	3-01	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	South Pond Energy Park	600	draft permit	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm /2.5 ppm NG; 36/10 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
FL	North Pond Energy Park	430	applic. under review	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
FL	Calpine Blue Heron Energy Center	1,080	draft permit	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NOx; CatOx - $1,553/ton CO
FL	Jacksonville Electric Authority - Brandy Branch (revision)	200	03/29/2002	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR	3-hr	Conversion of 2 SC units to 2 CC units
FL	CPV - Atlantic Power	250	05/03/2001	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation

FL	Orlando Utilities - Curtis H Stanton Energy Center	633	09/26/2001	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
FL	Broward Energy Center	775	05/15/2002	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
FL	Belle Glade Energy Center	600	01/28/2002	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
FL	Manatee Energy Center	600	01/17/2002	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
FL	CPV Pierce Power Generation Facility	250	08/17/2001	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
FL	Fort Pierce Repowering Project	180	08/15/2001	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
FL	TECO Bayside Power Station (repowering)	1,032	01/09/2002	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)
FL	CPV Cana Power Generation Facility	245	01/17/2002	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FL	FPL Martin	1,150	04/16/2003	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI	24-hr	PA = Power Augmentation
FL	FPL Manatee	1,150	04/15/2003	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN	24-hr	PA = Power Augmentation
FL	FPC - Hines Energy Complex	530	09/19/2003	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG/10 ppm FO	SCR	24-hr	SCONOx - $8,597/ton NOx;
FL	FPL Turkey Point	1,150	draft permit	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	2.0 ppm NG/8.0 ppm FO	SCR	24-hr	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx
GA	Georgia Power - Wansley (Oglethorpe Power)	2,280	07/28/2000	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
GA	Duke Energy Murray, LLC	1,240	2-01	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.0 ppm*	DLN/SCR		NOx and CO BACT limits were lowered from 3.5 ppm and 22 ppm after the permit was issued in response to a settlement with an Environmental Group
GA	Duke Energy Buffalo Creek, LLC	620	applic. under review	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOx - $19,948/ton NOx; CatOx - $2,469/ton CO
GA	Augusta Energy LLC	750	09/28/2001	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - $17,490/ton NOx; CatOx - $1,828/ton CO

GA	Oglethorpe Power Corp.- Wansley	521	01/15/2002	2	2	SW V84.3a2 (167 MW)	NG	CC	8,760	3.0 ppm	SCR		
GA	GenPower Rincon	528	03/24/2003	2	2	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm	SCR		
GA	Effingham Power Co.	525	12/27/2001	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
GA	Peace Valley Generation Co., LLC	1,550	draft permit	6	4	GE 7FA (170 MW)	NG	CC/SC	8,760/2,500	2.5/9.0 ppm	SCR/DLN	3-hr	
GA	Savannah Electric and Power - Plant McIntosh	1,260	04/17/2003	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.5 ppm NG; 6 ppm FO	SCR		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
GA	Live Oak Co., LLC	600	applic. under review	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
GA	Big River Power, LLC	855	applic. under review	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	3.0 ppm NG; 8.0 ppm FO	SCR/DLN; WI		SCR - $5,075/ton NOx; CatOx - $4,712/ton CO
KY	Kentucky Pioneer Energy	540	06/08/2001	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
KY	Duke Energy Trimble	1,240	applic. under review	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm	SCR		
MS	LS Power, LP (Batesville)	1,100	11/07/1999	3	3	SW 501G (281 MW)	NG; FO	CC	8,760 (10% FO)	9 ppm NG; 42 ppm FO	DLN; WI		
MS	Mississippi Power Corp., Plant Daniel	1,000	12-98	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.018 lb/MMBtu	DLN/SCR		
MS	Duke Energy Hinds, L.L.C.	520	01/07/2000	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
MS	Duke Energy Attala, L.L.C.	520	4-00	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
MS	Cogentrix Energy, Southaven Power Project	800	04/25/2000	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		
MS	Cogentrix Energy, Caledonia Power Project	800	3-01	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
MS	GenPower - McAdams LLC	528	08/16/2000	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
MS	Lone Oak Energy Center	800	11/13/2001	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
MS	Lee Power Partners	1,000	03/09/2001	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
MS	LSP-Pike Energy LLC	1,100	11/14/2000	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
MS	Magnolia Energy	900	05/31/2001	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
MS	Reliant Energy - Choctaw Co., LLC	844	06/13/2001	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOx - $48,663/ton NOx; CatOx - $3,550/ton CO
MS	Crossroads Energy Center	580	06/24/2002	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO
MS	Choctaw Gas Generation, LLC	700	12/13/2001	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		

MS	LSP Energy (Granite Power)	300	11/13/2001	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR	3-hr	
MS	Panada Black Prairie LP	1,040	applic. under review	4	4	F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	GE7FA or SW501F
NC	Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	2,040	applic. under review	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	-3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
NC	Carolina Power & Light, Rowan Co. (revision)	1,110	draft permit	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
NC	Fayetteville Generation	500	01/10/2002	2	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1000 FO	2.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI		CO level for FO depends on Load
NC	GenPower Earleys, LLC	528	01/14/2002	2	2	GE 7FA (170 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO
NC	Mirant Gastonia	1,200	05/28/2002	4	4	"F" Class (175 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Carolina Plant	1,300	applic. under review	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2.5/3.5 ppm; 13/18 ppm	SCR	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Mountain Creek - Granville Energy Center	911	applic. under review	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
NC	Dominion Person, Inc.	1,100	applic. under review	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm; 15 ppm FO	SCR		
NC	Forsyth Energy Projects	812	01/23/2004	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	2.5/3.5 ppm NG; 13/18 ppm FO	SCR	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels
SC	Santee Cooper, Rainey Generating Station	870	4-00	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC	SC Electric & Gas - Urquhart	444	9-00	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NOx, SO2 and PM10 PSD Review
SC	Columbia Energy	515	4-01	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONOx - no analysis; CatOx - $1,611/ton CO
SC	GenPower Anderson	640	07/03/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
SC	Greenville Power Project	810	applic. under review	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 20 ppm FO	SCR		SCONOx - $18,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr
SC	Jasper County Generating Facility	1,260	05/28/2002	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2.5 ppm NG; 7.5 ppm FO	SCR	24-hr	SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO

SC	Cherokee Falls Combined-Cycle Facility	1,260	applic. under review	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - $22,434/ton NOx; CatOx - $2,500/ton CO
SC	Fork Shoals Energy, LLC	1,150	applic. under review	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
SC	Palmetto Energy Center	970	applic. under review	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO
TN	Vanderbilt University	10	5-00	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		
TN	Memphis Generation LLC	1,050	04/09/2001	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
TN	Haywood Energy Center (Calpine)	900	02/01/2002	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TN	TVA - Franklin	610	draft permit	2	2	GE 7FA (195 MW)	NG	CC	8,760	3.5 ppm	SCR		
TN	Southern Power Co.	1,940	applic. under review	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN: SCR/WI		

Abbreviations:
GE = General Electric
SW = Siemens Westinghouse
NG = Natural Gas
FO = Fuel Oil
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction

Source: www.epa.gov/region4/air/permits

State	Facility	# of New MW	Final Permit Issued	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Region 4													
AL	Alabama Power - Olin Cogeneration	137	12/01/1997	1	1	GE 7EA (80 MW)	NG	CC	8,760	0.07 lb/MMBtu	GCP		Power Augmentation
AL	Alabama Power - GE Plastics Cogeneration	100	05/01/1998	1	1	GE 7EA (80 MW)	NG	CC	8,760	0.08 lb/MMBtu (combined)	GCP		
AL	Alabama Power, Plant Barry	800	08/01/1998	3	3	GE 7FA (170 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
AL	Alabama Power, Plant Barry	200	08/01/1999	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
AL	Mobile Energy, LLC - Hog Bayou	200	1-99	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
AL	Alabama Power - Theodore Cogeneration Facility	210	3-99	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
AL	Tenaska Alabama Partners	846	11-99	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
AL	Georgia Power - Goat Rock	-	4-00	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
AL	Georgia Power - Goat Rock (revision of above PSD application)	2,460	4-01	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
AL	Alabama Electric Cooperative - Gantt Plant	500	3-00	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
AL	South Eastern Energy Corp.	1,500	1-01	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
AL	Calpine Solutia - Decatur	700	6-00	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
AL	Calpine BP Amoco	700	6-00	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
AL	Tenaska Alabama II Generating Station	900	2-01	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
AL	Hillabee Energy Center	700	1-01	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
AL	Duke Energy - Alexander City	1,260	2-01	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
AL	GenPower - Kelly, LLC	1,260	1-01	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
AL	Blount County Energy	800	1-01	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
AL	Alabama Power - Autaugaville	1,260	1-01	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
AL	Tenaska Alabama IV Partners	1,840	10/09/2001	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NOX; CatOx- $1,506/ton CO
AL	Duke Energy Autauga, LLC	630	10/29/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NOX; CatOx- $5,006/ton CO

AL	Duke Energy Dale, LLC	630	12/17/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	0.033 lb/mmbtu	GCP		SCONOx - $18,403/ton NOX; CatOx- $2,634/ton CO+VOC
AL	Barton Shoals Energy, LLC	1,200	07/15/2002	4	4	GE 7FA (170 MW)	NG	CC	8,760	10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB	GCP		EPA did not received application until 5/24/02
FL	City of Lakeland, McIntosh Power Plant	250	7-10-98	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm NG; 90 ppm FO	GCP		Power Augmentation
FL	Santa Rosa Energy Center, Sterling Fibers Mfg. Facility	241	12-4-98	1	1	GE 7FA (167 MW)	NG	CC	8,760	9 ppm; 24 ppm w/ DB	GCP		If a different CT is used, SCR may be required to meet 6 ppm NOx)
FL	Kissimmee Utility Authority, Cane Island Power Park -Unit 3	250	draft permit	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
FL	Duke Energy - New Smyrna Beach	500	draft permit	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
FL	City of Tallahassee - Purdom	250	5-98	1	0	GE 7FA (160 MW)	NG; FO	CC	8,760	25 ppm NG; 90 ppm FO	GCP	3-hr test	
FL	Gulf Power - Smith Station	340	7-00	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NOx and CO; SA = steam augmentation
FL	Florida Power & Light - Sanford	2,200	9-99	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
FL	Gainesville Regional Utilities, Kelly Generating Station	133	2-00	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NOx
FL	Calpine Osprey Energy Center	527	07/05/2001	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
FL	Hines Energy (FPC)	530	06/07/2001	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NOx.; CatOx - $2,130/ton CO
FL	CPV - Gulfcoast	250	2-01	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
FL	TECO Gannon/Bayside	1,728	3-01	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	South Pond Energy Park	600	draft permit	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
FL	North Pond Energy Park	430	applic. under review	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
FL	Calpine Blue Heron Energy Center	1,080	draft permit	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NOx; CatOx - $1,553/ton CO
FL	Jacksonville Electric Authority - Brandy Branch (revision)	200	03/29/2002	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	14 ppm	GCP	24-hr	Conversion of 2 SC units to 2 CC units
FL	CPV - Atlantic Power	250	05/03/2001	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation

FL	Orlando Utilities - Curtis H Stanton Energy Center	633	09/26/2001	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
FL	Broward Energy Center	775	05/15/2002	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC & CC); 12 ppm (CC w/PA)	GCP	3-hr	SC; PA = Power
FL	Belle Glade Energy Center	600	01/28/2002	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	(SC); 14 ppm (CC	GCP	3-hr	SC; PA = Power
FL	Manatee Energy Center	600	01/17/2002	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/8 ppm; 4 ppm (CC w/PA)	GCP	3-hr	SC; PA = Power
FL	CPV Pierce Power Generation Facility	250	08/17/2001	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
FL	Fort Pierce Repowering Project	180	08/15/2001	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
FL	TECO Bayside Power Station (repowering)	1,032	01/09/2002	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm test avg.)	GCP	24-hr	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)
FL	CPV Cana Power Generation Facility	245	01/17/2002	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	GCP	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FL	FPL Martin	1,150	04/16/2003	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	10 ppm NG/8 ppm NG (12 ppm w/PA); 15 ppm FO	GCP	24-hr	PA = Power Augmentation
FL	FPL Manatee	1,150	04/15/2003	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
FL	FPC - Hines Energy Complex	530	09/19/2003	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	10 ppm NG/20 ppm FO	GCP	24-hr	SCONOx - $8,597/ton NOx;
FL	FPL Turkey Point	1,150	draft permit	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PK&DB; 8.0 ppm FO	GCP	24-hr	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx
GA	Georgia Power - Wansley (Oglethorpe Power)	2,280	07/28/2000	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
GA	Duke Energy Murray, LLC	1,240	2-01	4	4	GE 7FA (170 MW)	NG	CC	8,760	12 ppm*	GCP		NOx and CO BACT limits were lowered from 3.5 ppm and 22 ppm after the permit was issued in response to a settlement with an Environmental Group
GA	Duke Energy Buffalo Creek, LLC	620	applic. under review	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - $19,948/ton NOx; CatOx - $2,469/ton CO
GA	Augusta Energy LLC	750	09/28/2001	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2 ppm NG; 2 ppm FO	CatOx		SCONOx - $17,490/ton NOx; CatOx - $1,828/ton CO

GA	Oglethorpe Power Corp.-Wansley	521	01/15/2002	2	2	SW V84.3a2 (167 MW)	NG	CC	8,760	2.0 ppm	CatOx		
GA	GenPower Rincon	528	03/24/2003	2	2	GE 7FA (170 MW)	NG	CC	8,760	2.0 ppm	CatOx		
GA	Effingham Power Co.	525	12/27/2001	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
GA	Peace Valley Generation Co., LLC	1,550	draft permit	6	4	GE 7FA (170 MW)	NG	CC/SC	8,760/2,500	2.0 ppm/8.0 ppm	CatOx/GCP	3-hr	
GA	Savannah Electric and Power - Plant McIntosh	1,260	04/17/2003	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.0 ppm	CatOx		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
GA	Live Oak Co., LLC	600	applic. under review	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP		
GA	Big River Power, LLC	855	applic. under review	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.o ppm FO	GCP		SCR - $5,075/ton NOx; CatOx - $4,712/ton CO
KY	Kentucky Pioneer Energy	540	06/08/2001	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	GCP	3-hr	
KY	Duke Energy Trimble	1,240	applic. under review	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	9/13.9/20 ppm	GCP		
MS	LS Power, LP (Batesville)	1,100	11/07/1999	3	3	SW 501G (281 MW)	NG; FO	CC	8,760 (10% FO)	30.3 ppm NG; 36 ppm FO	GCP		
MS	Mississippi Power Corp., Plant Daniel	1,000	12-98	4	4	GE 7FA (170 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
MS	Duke Energy Hinds, L.L.C.	520	01/07/2000	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
MS	Duke Energy Attala, L.L.C.	520	4-00	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
MS	Cogentrix Energy, Southaven Power Project	800	04/25/2000	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
MS	Cogentrix Energy, Caledonia Power Project	800	3-01	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
MS	GenPower - McAdams LLC	528	08/16/2000	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
MS	Lone Oak Energy Center	800	11/13/2001	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
MS	Lee Power Partners	1,000	03/09/2001	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
MS	LSP-Pike Energy LLC	1,100	11/14/2000	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
MS	Magnolia Energy	900	05/31/2001	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
MS	Reliant Energy - Choctaw Co., LLC	844	06/13/2001	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONOx - $48,663/ton NOx; CatOx - $3,550/ton CO
MS	Crossroads Energy Center	580	06/24/2002	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO

MS	Choctaw Gas Generation, LLC	700	12/13/2001	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
MS	LSP Energy (Granite Power)	300	11/13/2001	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP	3-hr	
MS	Panada Black Prairie LP	1,040	applic. under review	4	4	F" Class (175 MW)	NG	CC	8,760	7.6 ppm or 80 ppm	GCP		GE7FA or SW501F
NC	Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	2,040	applic. under review	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
NC	Carolina Power & Light, Rowan Co. (revision)	1,110	draft permit	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
NC	Fayetteville Generation	500	01/10/2002	2	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1000 FO	9 ppm NG; 20-41 ppm FO	GCP		CO level for FO depends on Load
NC	GenPower Earleys, LLC	528	01/14/2002	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO
NC	Mirant Gastonia	1,200	05/28/2002	4	4	"F" Class (175 MW)	NG	CC	8,760	15 or 30 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Carolina Plant	1,300	applic. under review	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Mountain Creek - Granville Energy Center	911	applic. under review	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (24.3 ppm w/DB)	GCP		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
NC	Dominion Person, Inc.	1,100	applic. under review	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	9 ppm NG (20 ppm w/DB) 20 ppm FO	GCP		
NC	Forsyth Energy Projects	812	01/23/2004	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	11.6 ppm NG (25.9 ppm w/DB); 15.7 ppm FO (25.1 ppm w/DB)	GCP	3-hr	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels
SC	Santee Cooper, Rainey Generating Station	870	4-00	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC	SC Electric & Gas - Urquhart	444	9-00	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NOx, SO2 and PM10 PSD Review
SC	Columbia Energy	515	4-01	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
SC	GenPower Anderson	640	07/03/2001	2	2	GE 7FA (170 MW)	NG	CC	8,760	11.7 ppm	GCP		
SC	Greenville Power Project	810	applic. under review	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	12.3 ppm NG; 16.5 ppm FO	GCP		SCONOx - $18,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr

SC	Jasper County Generating Facility	1,260	05/28/2002	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)	GCP		SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO
SC	Cherokee Falls Combined-Cycle Facility	1,260	applic. under review	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	0.063 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		SCONOx - $22,434/ton NOx; CatOx - $2,500/ton CO
SC	Fork Shoals Energy, LLC	1,150	applic. under review	2	2	"F" Class (175 MW)	NG	CC	8,760	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	
SC	Palmetto Energy Center	970	applic. under review	3	3	GE 7FB (180 MW)	NG	CC	8,760	15 ppm (31 ppm w/DB)	GCP		SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO
TN	Vanderbilt University	10	5-00	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
TN	Memphis Generation LLC	1,050	04/09/2001	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
TN	Haywood Energy Center (Calpine)	900	02/01/2002	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TN	TVA - Franklin	610	draft permit	2	2	GE 7FA (195 MW)	NG	CC	8,760	25 ppm	GCP		
TN	Southern Power Co.	1,940	applic. under review	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	0.035 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		

Abbreviations:
GE = General Electric
SW = Siemens Westinghouse
NG = Natural Gas
FO = Fuel Oil
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction

Source: www.epa.gov/region4/air/permits

Appendix F
Dispersion Modeling Protocol

BLACK & VEATCH

11401 Lamar Avenue
Overland Park, Kansas 66211 USA

Tel: (913) 458-2000

Black & Veatch Corporation

Florida Municipal Power Agency
Treasure Coast Energy Center Unit 1

B&V Project 138859
B&V File 32.1100
B&V Letter No. BV/TP-0002
Date: January 7, 2005

Al Linero
Florida Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Treasure Coast Energy Center Combined Cycle Unit 1 Project Class II and Class I Air Dispersion Modeling Protocols

The Florida Municipal Power Agency (FMPA) is implementing the installation of a Nominal Net 310 MW 1x1 F-Class combined cycle unit (Project) at the new Treasure Coast Energy Center near Fort Pierce, FL.

Since the proposed Project will result in emissions greater than the major source threshold for at least one prevention of significant deterioration (PSD) pollutant, the PSD significant emission levels (SELs) will apply to the project. As such, the Project will be considered a new PSD major stationary source by the Florida Department of Environmental Protection (FDEP). It is anticipated that the proposed Project will be major for the following pollutants: NO_x, CO, SO_2, VOC, PM/PM_{10}, and sulfuric acid mist; thereby requiring PSD review for those pollutants. As part of that review, an air dispersion modeling demonstration must be performed to ensure that the proposed Project will comply with the appropriate ambient air quality thresholds in the surrounding areas.

Prior to such demonstration, the enclosed air dispersion modeling protocols have been developed for your review in an effort to obtain concurrence with the proposed modeling

Florida Municipal Power Agency
Treasure Coast Energy Center Unit 1

B&V Project 138859
B&V File 32.1100
B&V Letter No. BV/TP 0002
January 7, 2005

methodologies. The modeling methodologies presented in this document were discussed with FDEP personnel at a pre-application meeting held at the FDEP offices in Tallahassee on December 15, 2004. We look forward to your concurrence with this modeling methodology at your earliest convenience. If you have any questions or comments, please feel free to contact me at 913-458-7928.

Regards,

BLACK & VEATCH

Tim Hillman
Senior Air Quality Scientist

Attachments

cc: Rick Casey - FMPA
Kevin Fleming – FMPA
Susan Schumann – FMPA
Stanley Armbruster – B&V
Myron Rollins – B&V
Mike Soltys – B&V
Bob Holmes – B&V
File

FLORIDA MUNICIPAL POWER AGENCY
TREASURE COAST ENERGY CENTER
COMBINED CYCLE UNIT 1

CLASS II AND CLASS I AIR DISPERSION MODELING PROTOCOLS

PREPARED BY
BLACK & VEATCH

JANUARY 2005

ATTACHMENT 1

FLORIDA MUNICIPAL POWER AGENCY
TREASURE COAST ENERGY CENTER
COMBINED CYCLE UNIT 1

ISC CLASS II MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

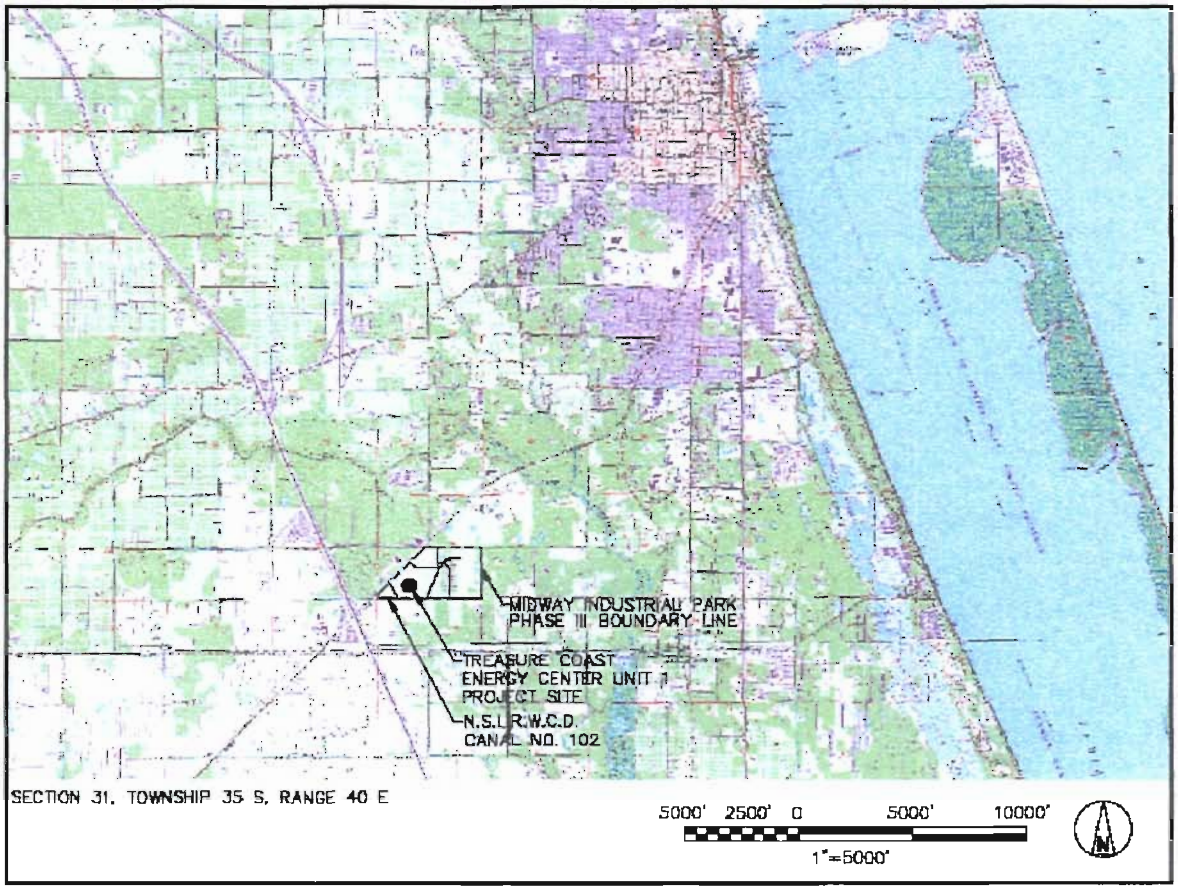
JANUARY 2005

Air Quality Modeling Assumptions and Methodology

Modeling Scenario:	As a new major stationary source, the air quality impact analysis (AQIA) will be performed for Unit 1, a nominally rated 310 MW (net) 1x1 combined cycle unit to be installed at the new Treasure Coast Energy Center site near Fort Pierce, St. Lucie County, Florida. The location of the proposed project is illustrated in the attached Figure.
Air Dispersion Model:	ISCST3 (Latest version)
Model Options:	USEPA Default and Flat terrain.
GEP & Downwash:	USEPA's BPIP program will be used to determine GEP stack height and direction specific building downwash parameters for the Unit 1 stack. Structures associated with the new site will be included in the BPIP analysis.
Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 100 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Dispersion Coefficients:	Rural: Based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.
Meteorological Data:	Refined level modeling sequential hourly meteorological data will consist of surface data and upper air data from the West Palm Beach Morrison Field (No. 12844) met station for the years 1987-1991. The files will be obtained from the Support Center for Regulatory Air Models website and processed with the USEPA meteorological processor PCRammet.
Pollutants to be Modeled:	The pollutants that are currently expected to be modeled are PM_{10}, NO_x, SO_2, and CO.
Source Modeling Parameters:	Representative combustion turbine performance and emissions data for the several operating configurations; including natural gas firing, fuel oil firing with water injection, evaporative cooling, and duct firing. The performance and emission data will be determined across 50, 75, and 100 percent load cases at ambient temperatures of 26, 59, 73, and 100 ^{o}F. Enveloping will be used to

determine the worst-case hourly emission rates and operating parameters for each load case that will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average data, at 100 percent load.

Modeled impacts:	It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. If the model predicted impacts exceed the SILs, additional agency consultation will be initiated regarding increment and cumulative air quality impact analyses.
Class I Analysis:	For analysis of the Everglades National Park Class I area, which lies beyond 50 km from the proposed project, the CALPUFF model will be used. The CALPUFF modeling protocol is discussed in Attachment 2 of this submittal.
Toxics:	No toxic modeling analysis is required.



Treasure Coast Energy Center Unit 1
Proposed Project Location

ATTACHMENT 2

FLORIDA MUNICIPAL POWER AGENCY
TREASURE COAST ENERGY CENTER
COMBINED CYCLE UNIT 1

CALPUFF CLASS I MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

JANUARY 2005

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1.0 Introduction

As part of the air impact evaluation for the proposed Treasure Coast Energy Center's Combined Cycle Unit 1 (hereinafter referred to as the Project), analyses of the proposed project's effect on the Everglades National Park (ENP) will be performed. The ENP is a Prevention of Significant Deterioration (PSD) Class I area located in southern Florida approximately 180 km south-southwest of the proposed project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) will be evaluated and compared to the recommended thresholds. Figure 1-1 presents the location of the proposed project site with respect to the ENP.

The methodology of the refined CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998 and the Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at ENP.

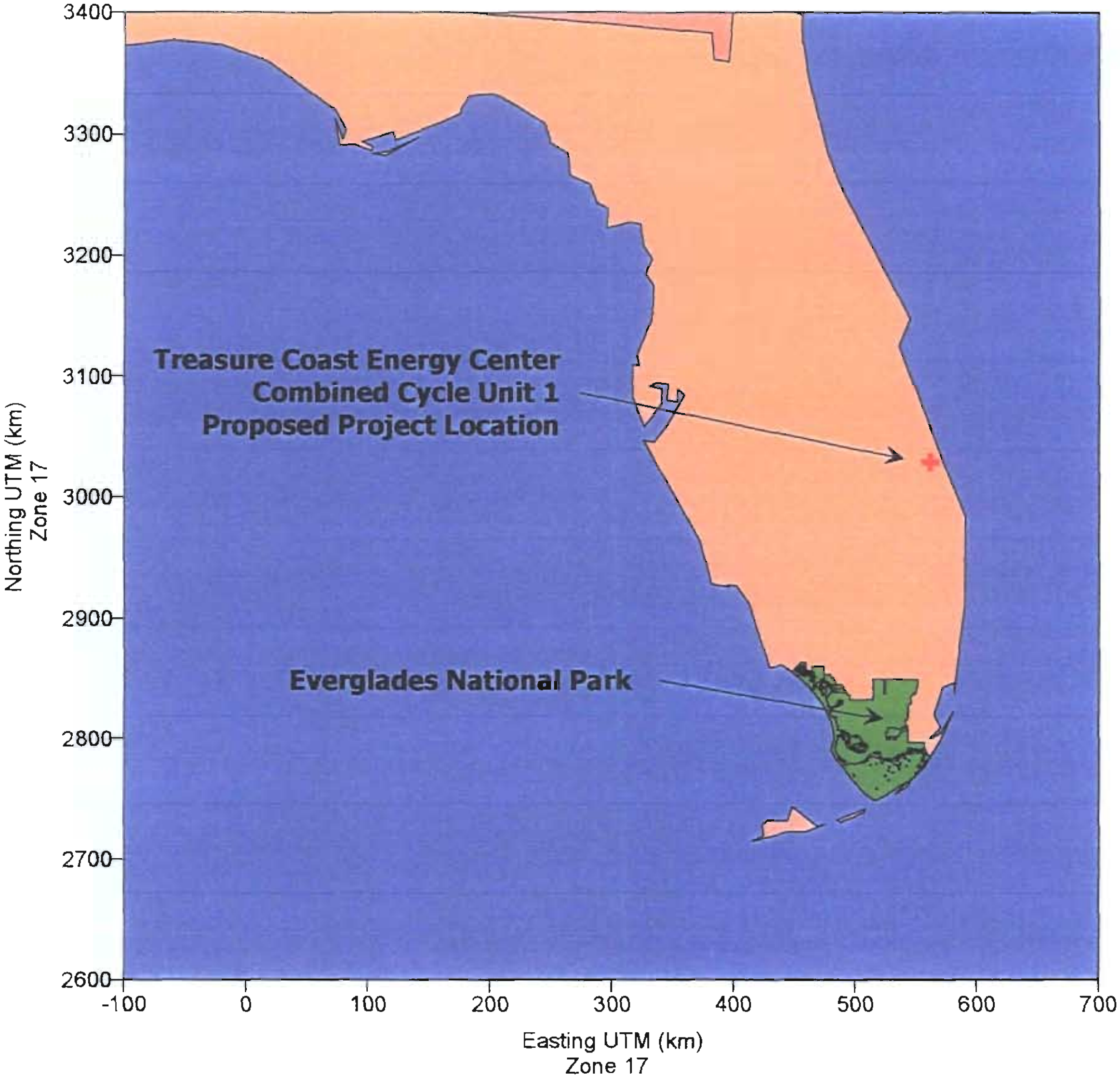


Figure 1-1 Proposed Project Location with respect to Everglades National Park

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, Version 5.711A, Level 040716) air modeling system will be used to model the proposed project and assess the AQRVs at ENP. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 will be used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis will include the facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

2.4 Receptor Locations

The CALPUFF analysis will use an array of discrete receptors for ENP, which were created and distributed by the NPS for standardized use in Class I analyses. Terrain throughout the ENP is included in the same NPS- provided receptor file.

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional plume rise, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST. Deposition: Highest predicted annual total sulfur and nitrogen values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 0.5 ppb; Monthly background ozone will be based on a review of the available monitoring stations' values averaged for each month. Additionally, hourly background ozone values from several reporting stations may be assessed for inclusion into the CALPUFF modeling.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.53A, Level 040716) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed project to the receptors at the ENP with at least a 50-km buffer zone in each direction. The modeling analysis will be performed in the UTM coordinate system. A rectangular modeling domain extending 215 km in the east-west (x) direction and 385 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 400 km Easting and 2,695 km Northing (based on UTM Zone 17, North American Datum (NAD) 1927 coordinates). The grid resolution for the domain will be 5 km. A grid spacing of 5 km yields 43 grid cells in the x-direction and 77 grid cells in the y-direction. Figure 2-1 illustrates the size and location of the modeling domain.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are used to populate the modeling domain with meteorological data. The analysis will use 1990 MM4, 1992 MM5, and 1996 MM5 mesoscale meteorological data sets to initialize the CALMET wind fields for each modeled year. The three years of MM data will be obtained from a NPS database provided to Black & Veatch. The extraction program accompanying the data will be used to obtain the

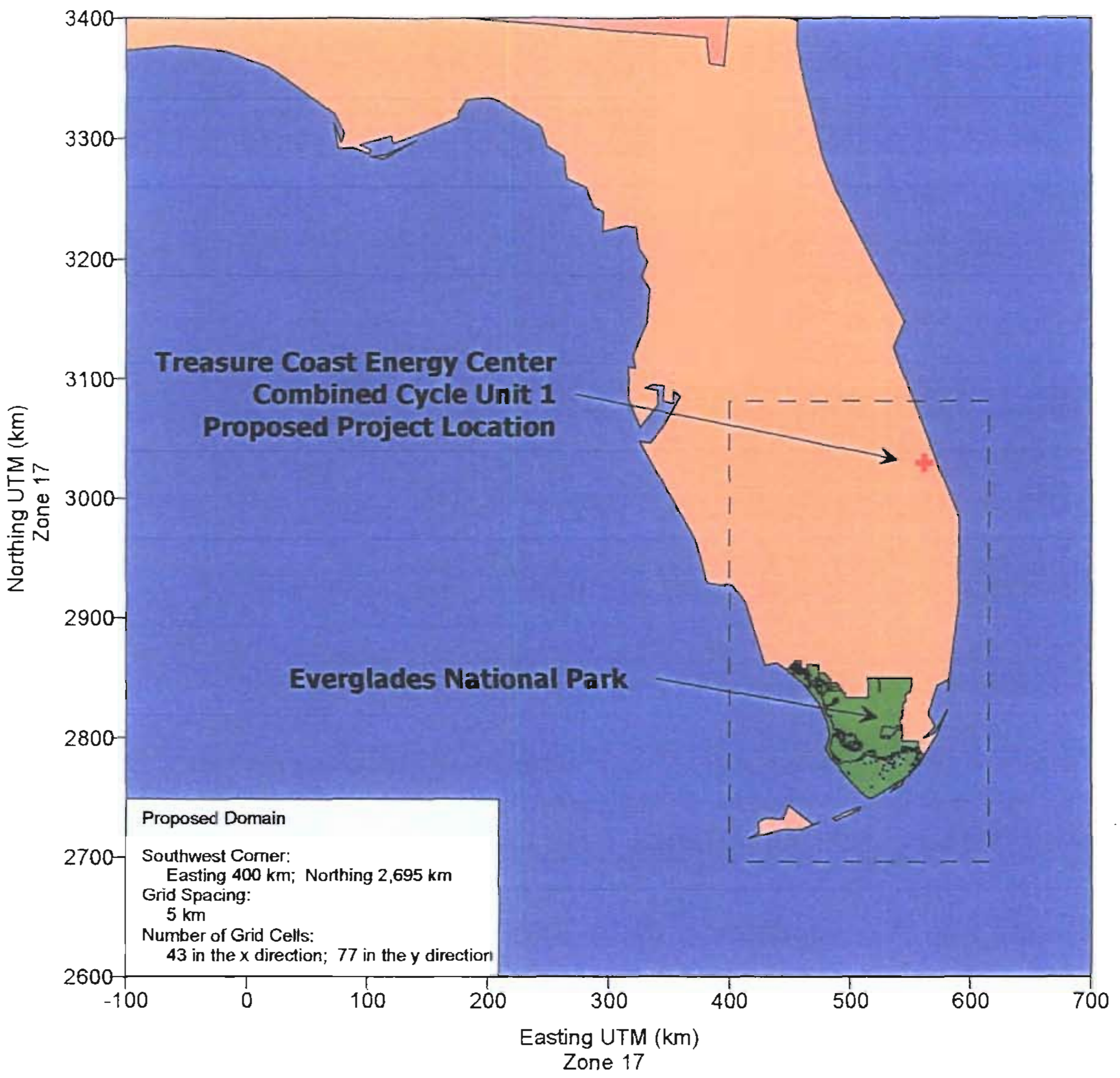


Figure 2-1 Proposed CALPUFF Modeling Domain

appropriate MM data points to cover the modeling domain. The 1990 MM4 and 1992 MM5 data have a horizontal spacing, or resolution, of 80 km. The 1996 MM5 data has a resolution of 36 km. The meteorological observations contained with the MM data sets are assumed to be of sufficient density, both temporally and spatially, to make the need for discrete meteorological station observation unnecessary. Thus, CALMET will be run with the No Observations mode developed in the latest version available from the model developer, EarthTech.

2.5.4 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain will be obtained from 1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data will be extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, will also be obtained from the USGS. Land-use values for the domain grid will be extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters will be combined with the terrain information in a processor called MAKEGEO. This processor will produce one GEO.DAT file for input to CALMET.

2.6 Project Emissions

The proposed Project will have the capability of operating in several configurations; including natural gas firing, fuel oil firing with water injection, evaporative cooling, and duct firing. The maximum pound per hour emission rates from Unit 1 at 100% load, across the several operating configurations, and the average annual temperature will be used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}. Only emissions from Unit 1 will be assessed for long-range transport.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the ENP, including regional haze, deposition, and Class I SILs.

3.1 Regional Haze Analysis

A regional haze analysis will be performed for the ENP for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the ENP lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the ENP. The background visual range, or constituents thereof, for the ENP will be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will closely follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (USEPA, 12/98) where appropriate. Table 3-1 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-1 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations *	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.
* *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (USEPA, 12/98).	

post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze will be calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. Based on recent correspondence with staff of the NPS for similar analyses, the relative humidity will be capped at 95 percent. A supplementary analysis will be performed with the relative humidity capped at 98 percent for informational purposes only. Method 7, which eliminates hours during which visibility limiting weather events occur, may be explored as necessary. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
   Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   b_{exts} = 3 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 1 x PM_{10}
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:
   b_{extb} = 3.912 / Visual range (km)
5. Compute the change in extinction coefficients:

in terms of deciviews:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

in terms of percent change of visibility:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed project's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2 Deposition Analyses

Deposition analyses will be performed for ENP for both total sulfur and total nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the USEPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 2.0 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results will be compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS).

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto the ENP will be calculated for NO_x, SO_2, and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Should the model predicted impacts onto the ENP exceed the Class I SILs, an appropriately derived inventory of PSD increment consuming sources will be developed through FDEP and modeled with the CALPUFF modeling system for comparison to the Class I Increment values.

Holmes, Allan R. (Bob)

From: O'Neal, Brian D.
Sent: Monday, December 20, 2004 10:30 AM
To: Rinkol, Michael J.; Holmes, Allan R. (Bob)
Cc: Hillman, Timothy M.
Subject: TCEC Modeling Protocol

Debbie Nelson (FDEP) got back to me today regarding some modeling issues/questions I left her with at the kick-off meeting last week.

She confirmed that the FDEP has no special modeling techniques when it comes to cooling towers; simply model as a point source.

She also confirmed that there are no Class II visibility areas near the project that we would need to model.

Holmes, Allan R. (Bob)

From: Nelson, Deborah [Deborah.Nelson@dep.state.fl.us]
Sent: Thursday, January 13, 2005 11:27 AM
To: O'Neal, Brian D.
Subject: Comments on Modeling Protocol for TCEC

Mr. O' Neal,

I will submit the Class I modeling protocol to the National Park Service for comments today. For the Class II, everything looked OK. Just make sure that you show how you determined the worst-case emission rates. For example, you stated in the protocol that for annual modeling impacts, the modeling will be based on annual average data at 100 percent load. Please show that the 100 percent load is a higher rate than 50 or 75% load. Please let me know if you have any questions and I will get back to you once I hear from the NPS.

Regards,

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

Holmes, Allan R. (Bob)

From: Nelson, Deborah [Deborah.Nelson@dep.state.fl.us]
Sent: Tuesday, February 15, 2005 8:20 AM
To: O'Neal, Brian D.
Subject: RE: TCEC comments

Brian,

For the Met Data, 87-91 WPB is OK. If you want to use surface from Vero and Upper Air from WPB you may do so as well.

No word yet from the Park Service. It may take a while - weeks. If you are pressed for time you can address EPA's comments on the Class I modeling and submit an application. However, please know that the Park Service will still have comments coming which may require additional modeling.

Regards,

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

-----Original Message-----
From: O'Neal, Brian D. [mailto:onealbd@bv.com]
Sent: Monday, February 14, 2005 2:19 PM
To: Nelson, Deborah
Subject: RE: TCEC comments

Two questions:
1) Do you have any thoughts on the surface met data issue of West Palm Beach that EPA raised? This is very important as we are in the depths of the modeling analysis now.

2) Any word from the NPS on their comments?

Best Regards,
Brian O'Neal

From: Nelson, Deborah [mailto:Deborah.Nelson@dep.state.fl.us]
Sent: Monday, February 07, 2005 2:09 PM
To: O'Neal, Brian D.
Subject: TCEC comments

Brian,

EPA has given me comments. The NPS has informed me that they have comments as well. However, the NPS is not ready to give those to me yet. EPA's comments are as follows:

ISC-PRIME Model - A modification to the Class II area modeling protocol indicates ISC-PRIME is the proposed dispersion model. This is not an Appendix W regulatory model. Project specific approval is needed for the application of a non-regulatory model. Section 3.2.2 of the Guideline on Air Quality Models (40 CFR 51 Appendix W) provides the conditions and documentation needed to obtain approval for the application of an alternated, non-guideline model. The reason ISCST3 is not appropriate for this application (Section 3.2.2.(b)) should be demonstrated and the basis for the acceptance of ISC-PRIME (section 3.2.2.(e)) should be provided.

You may send me your basis for using Prime and I can then forward it along to EPA if you'd like.

The TCEC appears to be located in the Midway Industrial Park. The fence line for TCEC should be the fence that is about the TCEC facility not that about the total industrial park (i.e., the fence line about the land owned or controlled by Florida Municipal power Agency).
- I n addition to the maximum modeled concentrations, all concentrations challenging the maximum values (e.g., within 10 % of the maximum modeled concentration) should be modeled with a refined 100-m resolution grid.

The West Palm Beach meteorological data should be evaluated relative to other stations that may be more representative of the project locations (e. g., Vero Beach).
- A more recent 5-year period of record should be considered. The period of 1986-91 is more than a decade old.
I will look more into this one and get back to you.

The pollutants to be modeled depends on the estimated emissions rates. All pollutant with significant emission rates should be modeled.
If emitted in sufficient amounts, PM2.5 and VOC (ozone) should be included in the PSD impact assessment

The 2.5 and VOC assessment should be a qualitative one.

Only emissions from the combined cycle combustion turbine are included in the protocol. Emissions from other facility components should be addressed.
- Emission values to be modeled should be associated with the maximum impacts not necessarily the maximum emission levels.

The components of the Additional Analysis portion of the required PSD impact analysis should be addressed. This includes impacts associated with growth, impacts on soils and vegetation, and visibility impacts to sensitive receptors within the impact area.
- The ambient air quality monitoring requirement should be addressed.

Class I Comments from EPA

FLM Review - The FLM for both Everglades NP and Chassahowitzka should be provided an opportunity to comment on the proposed modeling protocol.

2) Chassahowitzka Analysis - Because Chasshowitzka appears to be about the same distance from the proposed project, this Class I area should be included in the analysis.

3) CALMET Settings - When available, the horizontal and vertical CALMET grid settings should be provided. These should take into consideration the NWS data selected for inclusion in the modeling.

4) No Observations Option
- Given a refined CALPUFF analysis appears to have been selected, the CALPUFF no observations option is not an regulatory application of this model. Appendix W Section 9.3.1.2.d addresses this issue. NWS observations in the modeling domain should be included.

5) Project Emissions - The short-term and annual emission rates used in the Class II impact assessment should be used for this analysis. These should be the rates that produce the maximum impacts.

6) Additional Consultation - The protocol does not address the methods and procedure to be used if the extinction, deposition, and/or PSD increment assessments exceed their target values. If modeled values exceed the targets, the protocol should include further consultation with the regulatory agency with the possible need for a revised modeling protocol.

Let me know if you have any questions concerning these comments from EPA.

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

Holmes, Allan R. (Bob)

From: Nelson, Deborah [Deborah.Nelson@dep.state.fl.us]
Sent: Tuesday, February 22, 2005 8:14 AM
To: O'Neal, Brian D.
Subject: RE: 138859.32.1100 050218 Responses to EPA Comments on Modeling Protocol

I received comments from the EPA regarding your responses to their comments on the modeling protocol. They agree that all of your responses are appropriate.

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

-----Original Message-----
From: O'Neal, Brian D. [mailto:onealbd@bv.com]
Sent: Friday, February 18, 2005 3:46 PM
To: Nelson, Deborah
Cc: Kevin.Fleming@fmpa.com; SCHUMANN, SUSAN @ FMPA; AngelaM@hgslaw.com; Jody.Lamar.Finklea@fmpa.com; Fred.Bryant@fmpa.com; Armbruster, Stanley A. (Stan); Rollins, Myron R.; Soltys, J. Michael (Mike); Hillman, Timothy M.; Holmes, Allan R. (Bob); TCEC; FortPierce@fmpa.com
Subject: 138859.32.1100 050218 Responses to EPA Comments on Modeling Protocol

Debbie,
Please find below our responses to the EPA comments on the Class I and Class II air dispersion modeling protocol for the Treasure Coast Energy Center. Let me know if you have any questions or concerns.

Best Regards,
Brian O'Neal

From: Nelson, Deborah [mailto:Deborah.Nelson@dep.state.fl.us]
Sent: Monday, February 07, 2005 2:09 PM
To: O'Neal, Brian D.
Subject: TCEC comments

Brian,

EPA has given me comments. The NPS has informed me that they have comments as well. However, the NPS is not ready to give those to me yet. EPA's comments are as follows:

ISC-PRIME Model - A modification to the Class II area modeling protocol indicates ISC-PRIME is the proposed dispersion model. This is not an Appendix W regulatory model. Project specific approval is needed for the application of a non-regulatory model. Section 3.2.2 of the Guideline on Air Quality Models (40 CFR 51 Appendix W) provides the conditions and documentation needed to obtain approval for the application of an alternated, non-guideline model. The reason ISCST3 is not appropriate for this application (Section 3.2.2.(b)) should be demonstrated and the basis for the acceptance of ISC-PRIME (section 3.2.2.(e)) should be provided.

You may send me your basis for using Prime and I can then forward it along to EPA if you'd like.
[Black & Veatch] That won't be necessary. The ISC-PRIME air dispersion model was simply inquired about as to its availability for usage in the state of Florida and was not necessarily proposed as the preferred air dispersion model for the project. We do not wish to pursue approval of ISC-PRIME at this point.

The TCEC appears to be located in the Midway Industrial Park. The fence line for TCEC should be the fence that is about the TCEC facility not that about the total industrial park (i.e., the fence line about the land owned or controlled by Florida Municipal power Agency).
[Black & Veatch] Agreed.

- In addition to the maximum modeled concentrations, all concentrations challenging the maximum values (e.g., within 10 % of the maximum modeled concentration) should be modeled with a refined 100-m resolution grid.
[Black & Veatch] The project will comply with the request and the following protocol language is proposed: "If any maximum impact or controlling impact (i.e., a concentration within 10 percent of the maximum impact) occurs beyond the 100 m fine grid, a 100 m refined receptor grid surrounding the impact receptor out to a distance equal to the mid-point to the next receptor location in each direction will be placed around the impact to ensure that an absolute maximum concentration will be obtained from the model."

The West Palm Beach meteorological data should be evaluated relative to other stations that may be more representative of the project locations (e. g., Vero Beach).
- A more recent 5-year period of record should be considered. The period of 1986-91 is more than a decade old.
I will look more into this one and get back to you.
[Black & Veatch] I realize you are looking into this Debbie. However, allow me to offer the following rationale for selecting West Palm Beach 1987 to 1991 data. The EPA's SCRAM website does not contain the required consecutive 5-year data set for Vero Beach. Also, 1987 to 1991 is the latest data set common to both the upper air and surface data stations available on the SCRAM website. Please let us know as soon as possible how to proceed on this issue.

The pollutants to be modeled depends on the estimated emissions rates. All pollutant with significant emission rates should be modeled.
If emitted in sufficient amounts, PM2.5 and VOC (ozone) should be included in the PSD impact assessment

The 2.5 and VOC assessment should be a qualitative one.
[Black & Veatch] Agreed. The extent of our analysis will be to provide our emissions estimates and PTE calculations of these pollutants.

Only emissions from the combined cycle combustion turbine are included in the protocol. Emissions from other facility components should be addressed.
- Emission values to be modeled should be associated with the maximum impacts not necessarily the maximum emission levels.
[Black & Veatch] Agreed. Emissions from other operating equipment such as the auxiliary boiler, fire pump, shutdown generator, and the cooling tower will be addressed (including emissions estimates, PTE calculations, and air dispersion modeling) in the air permit application document.

The components of the Additional Analysis portion of the required PSD impact analysis should be addressed. This includes impacts associated with growth, impacts on soils and vegetation, and visibility impacts to sensitive receptors within the impact area.
[Black & Veatch] Agreed. The Additional Impact Analysis will be addressed in the air permit application document.

- The ambient air quality monitoring requirement should be addressed.
[Black & Veatch] Agreed. The ambient air quality monitoring requirement will be addressed in the air permit application document. Furthermore, it is anticipated that the model-predicted, ground-level impacts from the proposed project will be below the de minimus ambient monitoring thresholds.

Class I Comments from EPA

1) FLM Review - The FLM for both Everglades NP and Chassahowitzka should be provided an opportunity to comment on the proposed modeling protocol.
[Black & Veatch] We assume FDEP has this for action.

2) Chassahowitzka Analysis - Because Chasshowitzka appears to be about the same distance from the proposed project, this Class I area should be included in the analysis.
[Black & Veatch] While Chassahowitzka is approximately 260 km away from the proposed project (a single Combined Cycle Combustion Turbine fired primarily on natural gas with limited ultra low sulfur fuel oil firing capabilities), the modeling domain will be extended to incorporate the proposed project's effects upon Chassahowitzka.

3) CALMET Settings - When available, the horizontal and vertical CALMET grid settings should be provided. These should take into consideration the NWS data selected for inclusion in the modeling.
[Black & Veatch] The horizontal grid settings are provided in the modeling protocol. The vertical grid settings were not as they vary with height, but generally are more tightly spaced near the surface and ultimately capped at 3,000 meters. The vertical grid settings are as follows: 0, 20, 40, 80, 160, 300, 600, 1,000, 1,500, 2,200, 3,000 meters.

4) No Observations Option
- Given a refined CALPUFF analysis appears to have been selected, the CALPUFF no observations option is not an regulatory application of this model. Appendix W Section 9.3.1.2.d addresses this issue. NWS observations in the modeling domain should be included.

[Black & Veatch] With the No Observations Option being unacceptable, at our discretion, the Class I area air dispersion modeling analysis will consist of either a screening level analysis following the procedures set forth in EPA's *Interagency Workgroup on Air quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (December 1998), Earth Tech, Inc.'s *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* (September 2001), and the *Long-Range-Transport Screening Technique Using CALPUFF* document jointly authored by the National Park Service and the EPA or a full refined analysis that will include actual hourly data from surface, upper air, and precipitation stations within and around the new larger domain encompassing Chassahowitzka. Debbie, please be sure to communicate this updated methodology to the NPS.

5) Project Emissions - The short-term and annual emission rates used in the Class II impact assessment should be used for this analysis. These should be the rates that produce the maximum impacts.
[Black & Veatch] The maximum short-term emission rates will be used in the Class I modeling for all analyses.

6) Additional Consultation - The protocol does not address the methods and procedure to be used if the extinction, deposition, and/or PSD increment assessments exceed their target values. If modeled values exceed the targets, the protocol should include further consultation with the regulatory agency with the possible need for a revised modeling protocol.
[Black & Veatch] It is not expected that the proposed project will exceed any of the aforementioned target values. However, should the need arise, a cumulative source modeling methodology will be developed and presented to the FDEP for approval.

Let me know if you have any questions concerning these comments from EPA.

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

Holmes, Allan R. (Bob)

From: O'Neal, Brian D.
Sent: Thursday, March 03, 2005 5:56 PM
To: Nelson, Deborah
Cc: SCHUMANN, SUSAN @ FMPA; AngelaM@hgslaw.com; Jody.Lamar.Finklea@fmpa.com; Fred.Bryant@fmpa.com; Armbruster, Stanley A. (Stan); Rollins, Myron R.; Soltys, J. Michael (Mike); Hillman, Timothy M.; Holmes, Allan R. (Bob); TCEC; FortPierce@fmpa.com
Subject: RE: National Park Service Review of Treasure Coast Energy Modeling Protocol

Debbie,
Please find our response to the National Park Service's comments on our Class I air dispersion modeling protocol.

Based on the comments received from EPA Region IV, the proposed project's modeling domain has been extended to encompass both the Everglades National Park and the Chassahowitzka Wilderness Area. Given the new larger domain size requested by the EPA and the NPS Comment #2 below (to increase the grid resolution from 5 km to 3 km), a refined CALPUFF analysis becomes computer resource-intensive in nature and makes the CALMET output data files onerous to work with, store, and submit to the reviewing agency. In light of these considerations, it may be advantageous for the proposed project to choose the CALPUFF-Lite screening option.

The following are the modeling assumptions that will be invoked should the proposed project choose to perform CALPUFF-Lite screening modeling:
1) The Screening level analysis will follow the procedures set forth in the National Park Service's _Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report_ (December 2000), Earth Tech, Inc.'s _Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System_ (September 2001), and the _Long-Range-Transport Screening Technique Using CALPUFF_ document jointly authored by the National Park Service and the EPA.

2) Five years of National Weather Service data will be processed with CPRammet for use in the CALPUFF modeling. The data set will be 1987 through 1991 with surface data and upper air mixing height data from West Palm Beach, Florida. This is the same data set that was approved for use in the Class II air dispersion modeling demonstration. CPRammet is a modified version of the EPA meteorological processor PCRammet. It was created by Earth Tech, the developers of the CALPUFF modeling system. CPRammet was designed to alleviate two incompatibilities between PCRammet and the CALPUFF model: 1) PCRammet will not produce the necessary extended ISCST3 variables (e.g., friction velocity, Monin-Obukhov length, relative humidity, solar radiation, etc.) when input data are in CD-144 format and 2) PCRammet will not report solar radiation when an observed value is missing.
The data will be processed with CPRammet for wet deposition to produce the necessary extended ISCST3 variables. Values for surface roughness, albedo, Bowen ratio (average moisture), Monin-Obukhov length, and net radiation absorbed at the ground were derived from the June 1999 PCRammet User's Guide. For values where the specific land use type is required (i.e., surface roughness, albedo, and average moisture Bowen ratio), the Grassland land use category will be chosen and averaged over the 4 seasonal values provided to arrive at a single annual value for input into CPRammet. For the Monin-Obukhov length the Open Agricultural land use type and subsequent 2 meter value will be used. For the net radiation absorption value the rural value of 0.15 will be chosen. As indicated in the user's guide, anthropogenic heat flux will be assumed to be zero for areas outside highly urbanized locations. All 5 years of CPRammet processed data will be combined into a single 5-year meteorological data file.

3) Grid Settings: Since the screening methodology uses meteorological data from a single ISC meteorological data file, there is no spatial variation in meteorological or geophysical properties. Therefore, the minimum grid cell configuration of 2 grid cells in the x-direction and 2 grid cells in the y-direction will be used (4 grid cells total). A single layer will be used in the vertical since wind speed measurements taken at anemometer height will be scaled to stack-top height as in ISC. Therefore, the two cell face heights will be set to 0 meters (ground-level) and 5,000 meters (selected such that highest mixing height in the meteorological file does not exceed this value). The size of the domain will be of sufficient size to encompass the proposed project location, the Everglades National Park, and Chassahowitzka Wilderness Area with at least a 50 km buffer zone in each of the north, south, east, and west directions to allow for puffs to return to a Class I area due to a recirculating wind pattern.

4) The Mesopuff II chemical transformation methodology will be used with constant, default background values of ozone and ammonia (80 ppb and 10 ppb respectively).

5) Dry gas, dry particle, and wet deposition will be invoked.

6) The wind profile will be set to the ISC Rural setting with the calm wind speed set to 1.0 meters per second.

7) The only plume rise options that will be selected is Stacktip Downwash to simulate how a plume is handled in the ISC model.

8) The default Pasquill-Gifford coefficient with Rural ISC Curves will be selected for the dispersion option.

9) Terrain will be treated with the default Partial Plume Path Adjustment selection.

10) Emissions of NOx, SO2, PM10 (filterable and condensable), and SO4 will be input to the model. Furthermore, as requested, emissions of PM10 will be speciated based on size and composition. The recommendations on speciated particulate matter emissions estimates for natural gas and distillate oil fired turbines mentioned in the NPS comments below were requested from Don Shepherd as recommended. At this time, no response has been received. The proposed project will estimate the fraction of PM10 emissions that can be classified as filterable inorganic, filterable carbon, and condensable organic and will determine the various size categories for each composition. These speciated PM10 emissions will be classified into EC, SOA/OC, FPM (particles with mass mean diameters less than or equal to 2.5 microns), and CPM (particles with mass mean diameters greater than 2.5 microns but less than or equal to 10 microns).

11) Receptor rings will be created that pass through each Class I area. The receptor rings will have receptors spaced every 1 degree (i.e., 360 receptors per ring) with the proposed project's source located at the center of the ring. Each ring of receptors will have a single elevation. The elevation of the receptors in each ring will be set to the highest elevation found in the National Park Service-provided receptor database for each Class I area. The Everglades National Park will have 3 receptor rings passing through the area: one each at the nearest, mid-point, and most distant points of the area. Due to its small size, the Chassahowitzka Wilderness Area will have two receptor rings passing through the area: one each at the nearest and most distant points of the area. The highest impact occurring anywhere on the receptor rings for each Class I area will be reported as the maximum AQRV impact values for the proposed project. If necessary, the maximum impacts will be reported from the 90-degree and/or 45-degree arc of receptors on each side of the Class I area as indicated in the EPA/NPS *Long-Range-Transport Screening Technique Using CALPUFF* document.

12) The POSTUTIL processor will be used as described in the original Class I area air dispersion modeling protocol to determine the impacts of total sulfur and total nitrogen deposition in kg/ha/yr upon each Class I area.
The POSTUTIL processor will also be used to group the size-speciated particulate emissions into the appropriate compositions of EC, SOA/OC, FPM, CPM, and PM10 emissions by multiplying the nominal 1 gram per second emission rates in CALPUFF by the appropriate speciated PM10 emissions (based on size and composition).

13) Visibility will be computed by using the model-predicted components of NO3, SO4, OC/SOA, PMC, PMF, and EC. Visibility calculations will be performed as recommended in the FLAG document by using Method 6 and the Class I area-specific seasonal values of Hygroscopic, Non-Hygroscopic, Rayleigh, and Relative Humidity Factors given the in the document.

Regards,
Brian O'Neal

From: Nelson, Deborah [mailto:Deborah.Nelson@dep.state.fl.us]
Sent: Monday, February 28, 2005 11:21 AM
To: O'Neal, Brian D.
Subject: FW: National Park Service Review of Treasure Coast Energy Modeling Protocol

Comments from the Park Service...

Debbie Nelson
Meteorologist
Air Permitting South
850-921-9537
deborah.nelson@dep.state.fl.us

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Monday, February 28, 2005 11:32 AM
To: Nelson, Deborah
Cc: John_Bunyak@nps.gov; John_Notar@nps.gov; Don_Shepherd@nps.gov; HGebhart@air-resource.com
Subject: RE: National Park Service Review of Treasure Coast Energy Modeling Protocol

Debbie,
We have the following comments regarding the CALPUFF dispersion modeling protocol for the Treasure Coast Energy Center Combined Cycle Unit 1 prepared by Black and Veatch dated January 2005.

1. We agree with comments provided by Environmental Protection Agency (EPA) Region IV that the "no observation" mode of CALPUFF should not be employed. Our understanding from Black and Veatch's response to EPA's comments is that they will employ either a CALPUFF-Lite screening modeling approach, or a refined CALPUFF modeling analysis using appropriate National Weather Service (NWS) surface, upper air, and precipitation stations from the modeling domain. Either approach would be acceptable. However, the protocol lacks specific information about the CALPUFF-Lite screening option.

2. The applicant's proposed grid size for CALPUFF is 5 km, presuming that a refined modeling analysis is conducted. We would prefer that a smaller grid size be used. A 3-km horizontal grid spacing would be acceptable and would also define the nearby coastline (which can be important for plume dispersion) with greater resolution.

3. The modeling domain for this study includes both overland and overwater grid cells. Some NWS surface stations that might be employed in the meteorological data field development for the refined CALPUFF modeling are located along the coastline where they are subjected to the land breeze/sea breeze phenomena. We would caution the applicant to select appropriate "radius of influence" parameters so that the land breeze/sea breeze effects present in the NWS data do not extend too far inland or offshore.

4. Based on the response to EPA comments, the applicant is committing to model the maximum short-term emission rates, but the specific emissions were not listed. The protocol indicates that only emissions of nitrogen oxides (NOx), sulfur dioxide (SO2) and particulate matter (PM-10) will be modeled. The applicant should be advised that the PM-10 emissions need to include the condensable fraction and should not be based only on the filterable PM-10 emissions. Also, consistent with other recent CALPUFF modeling, the applicant should model stack emissions for primary sulfate (SO4) as well as speciated PM-10 (EC, SOA, & FPM). We have developed recommendations on sulfate and speciated particulate matter emission estimates for natural gas-fired and distillate oil-fired turbines. Please contact Don Shepherd (National Park Service Air Resources Division don_shepherd@nps.gov) for these emission estimates.

5. The applicant has proposed a background ammonia concentration of 0.5 ppb, which is from the IWAQM Phase II Report for "forested" areas. We do not believe that the proposed ammonia background data are representative of conditions in south Florida. Our understanding is that the land use along the likely trajectory to Everglades National Park consists primarily of agricultural lands, and undeveloped marshes/swamps. The immediate area surrounding the source is also urbanized to some degree. All of these lands would be expected to generate higher background ammonia levels than "forested" lands. As such, our recommendation is to use the 10 ppb background ammonia value listed by the IWAQM report for "grasslands" or at least computed a "weighted mean" based on the land use patterns actually present in the modeling domain.

Please contact me if there are any questions concerning our comments.

Thanks,

Dee Morse
Environmental Protection Specialist
National Park Service

Air Resources Division
(303) 969-2817
dee_morse@nps.gov

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Florida Municipal Power Agency
2. Site Name: Treasure Coast Energy Center
3. Facility Identification Number:
4. Facility Location...
   Street Address or Other Locator: 4585 Selvitz Road, Lot 8
   City: Fort Pierce County: St. Lucie Zip Code:
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: Susan Schumann
2. Application Contact Mailing Address...
   Organization/Firm: Florida Municipal Power Agency
   Street Address: 8553 Commodity Circle
   City: Orlando State: FL Zip Code: 32819
3. Application Contact Telephone Numbers...
   Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4. Application Contact Email Address: susan.schumann@fmpa.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	4-14-05
2. Project Number(s):	1110121-001-AC
3. PSD Number (if applicable):	PSD-FL-353
4. Siting Number (if applicable):	PA 05-48

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

[X] Air construction permit.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
	Unit 1 – GE PG7241 FA Combustion Turbine	AC1A	NA
	Auxiliary Boiler	AC1A	NA
	Diesel Engine Fire Pump	AC1A	NA
	Safe Shutdown Generator	AC1A	NA
	Fuel Oil Storage Tank – 990,000 gallon fuel oil storage tank	AC1F	NA
	Mechanical Draft Cooling Tower	AC1A	NA

Application Processing Fee

Check one: ☐ Attached - Amount: $_______________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : Roger Fontes – General Manager and CEO
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4.	Owner/Authorized Representative Email Address: roger.fontes@fmpa.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* [signature] 4/11/05 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   ______________________________ ____________________
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Stanley A. Armbruster, P.E.
   Registration Number: 30562
2. Professional Engineer Mailing Address...
   Organization/Firm: Black & Veatch
   Street Address: 11401 Lamar Avenue
   City: Overland Park State: KS Zip Code: 66211
3. Professional Engineer Telephone Numbers...
   Telephone: (913) 458-2763 ext. Fax: (913) 458-2934
4. Professional Engineer Email Address: ArmbrusterSA@bv.com
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

[signature] April 14, 2005
Signature Date

(seal)

STANLEY A. ARMBRUSTER LICENSE 30562 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 561.5161 North (km) 3028.9963		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: 4	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name Jim Hay
2. Facility Contact Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819
3. Facility Contact Telephone Numbers: Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4. Facility Contact Email Address: jim.hay@fmpa.com

Facility Primary Responsible Official
Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	N
NOX	A	N
PM	A	N
PM10	A	N
SO2	B	N
VOC	B	N
SAM	B	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. A [ ] Previously Submitted, Date:_______
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. B [ ] Previously Submitted, Date:_______
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. C [ ] Previously Submitted, Date:_______

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: [x] Attached, Document ID: Attach. D [ ] Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: [x] Attached, Document ID: Attach. E
3.	Rule Applicability Analysis: [x] Attached, Document ID: Attach. F
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): [x] Attached, Document ID: Attach. G [ ] Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): [ ] Attached, Document ID:_________ [x] Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): [x] Attached, Document ID: Attach. H [ ] Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): [x] Attached, Document ID: Attach. I [ ] Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): [x] Attached, Document ID: Attach. J [ ] Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): [x] Attached, Document ID: Attach. K [ ] Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:_________ [x] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:________ ☐ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:__________ ☐ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable	

Additional Requirements Comment

Attachment S includes a CD with air dispersion modeling files.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Unit 1 – GE PG7241 FA Combustion Turbine.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	[x] Yes ☐ No

9. Package Unit:
   Manufacturer: GE Model Number: PG7241 FA

10. Generator Nameplate Rating: 170 MW for the CT (approximate):
    130 MW for the STG (approximate)

11. Emissions Unit Comment: The combined cycle combustion turbine will include HRSG duct firing capability.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Dry low NO_x burners in conjunction with selective catalytic reduction will be used to control NO_x emissions when firing natural gas. Water injection in combination with selective catalytic reduction will be used to control NO_x emissions when firing fuel oil.
2. Control Device or Method Code(s): 205, 028, 139

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:			
2. Maximum Production Rate:			
3. Maximum Heat Input Rate:	1,876.8 million Btu/hr (HHV) – CT firing natural gas 2,044.4 million Btu/hr (HHV) – CT firing fuel oil 565.3 million Btu/hr (HHV) – Duct Burner		
4. Maximum Incineration Rate:	pounds/hr tons/day		
5. Requested Maximum Operating Schedule:			
CT firing natural gas	24 hours/day	7 days/week	
	52 weeks/year	8,760 hours/year	
Duct burner firing natural gas	24 hours/day	7 days/week	
	52 weeks/year	8,760 hours/year	
CT firing fuel oil	24 hours/day	7 days/week	
	52 weeks/year	500 hours/year	
6. Operating Capacity/Schedule Comment: The unit will be operated between 40 and 100 percent of full load. The maximum heat input rate shown in Field 3 is with operation at 100% load at the site minimum ambient temperature of 26°F. Note that the heat input rate is a function of ambient temperature. As discussed in FDEP Guidance Document DARM-OGG-07, higher CT inlet temperatures will result in a lower heat input rate (MMBtu/hr) and vice versa. Variations of heat input (capacity) are to be expected due to the range of ambient temperatures and humidities encountered at the site. When they become available, the CT operating curves (capacity vs. inlet air temperature) will be provided to the Department. It is requested that the permit for this unit include Conditions 1 and 2 of DARM-OGG-07. We request inclusion of the standard permitting note that the heat input rates are provided for informational purposes only and are not intended to be enforceable limits.			

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Heat Recovery Steam Generator Exhaust Stack	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: V	6. Stack Height: 170 feet	7. Exit Diameter: 18 feet
8. Exit Temperature: 170°F	9. Actual Volumetric Flow Rate: 958,300 acfm	10. Water Vapor: 12%

11. Maximum Dry Standard Flow Rate: 793,000 dscfm	12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.5161 North (km): 3028.9963	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment: Emission point information given in Fields 8 through 11 are based on firing natural gas with operation at 100% load and at the site average ambient temperature of 73°F and HRSG duct firing. This information will vary depending on ambient temperature and load. The following information is based on firing ULS fuel oil with operation at 100% load and at the site average ambient temperature of 73°F and HRSG duct firing.
Field 8: 250°F
Field 9: 1,135,600 acfm
Field 10: 15%
Field 11: 830,600 scfm

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): Natural gas used in the combustion turbine		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.93	5. Maximum Annual Rate: 16,907	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 970 (HHV)
10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate given in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 26°F. The maximum natural gas use rate given in Field 5 is based on 100 percent load operation for 8,760 hours per year at the site minimum ambient temperature of 26°F. The fuel use rates do not include duct burner operation.		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): No. 2 fuel oil used in the combustion turbine		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand gallons burned	
4. Maximum Hourly Rate: 14.9	5. Maximum Annual Rate: 7,450	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate given in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 26°F. The maximum fuel oil use rate given in Field 5 is based on 100 percent load operation for 500 hours per year at the site minimum ambient temperature of 26°F.		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): Natural gas used in duct burner.		
2. Source Classification Code (SCC):	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.58	5. Maximum Annual Rate: 5,105	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 970 (HHV)
10. Segment Comment: The duct burner is fired only with natural gas. The duct burner may operate when firing either natural gas or fuel oil in the combustion turbine.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOX	205, 139 (NG) 028, 139 (FO)		EL
PM			
PM10			
SO2			WP
VOC			
SAM			WP

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 92.4 lb/hour 228.5 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential CO emissions are based on operation in combined cycle mode firing fuel oil in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly CO emission rate is 92.4 lb/hour.
The maximum annual potential CO emissions are based on operation in combined cycle mode firing fuel oil in the combustion turbine at 100 percent load for 500 hours per year, firing natural gas in the combustion turbine at 100 percent load the remainder of the year and firing natural gas in the duct burner for 8,760 hours per year and operation at the site average ambient temperature of 73°F.
Annual emissions = (86.2 lb/hr x 500 hr/yr + 50.1 lb/hr x 8,260 hr/yr) x 1 ton/2,000 lb = 228.5 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The following are the maximum CO emission rates in ppmv, dry at 15 percent O_2:
Combined cycle natural gas firing: 10.4 ppmvd
Combined cycle fuel oil firing: 15.4 ppmvd
Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 81.1 lb/hour 87.1 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data and proposed BACT emission levels.
The maximum hourly potential NO_x emissions are based on firing fuel oil in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly NO_x emission rate is 81.1 lb/hour.
The maximum annual potential NO_x emissions are based on firing fuel oil in the combustion turbine at 100 percent load for 500 hours per year, firing natural gas in the combustion turbine at 100 percent load for the remainder of the year, and firing natural gas in the duct burner for 8,760 hours per year and operation at the site average ambient temperature of 73°F.
Annual emissions = (76.0 lb/hr x 500 hr/yr + 16.5 lb/hr x 8,260 hr/yr) x 1 ton/2,000 lb = 87.1 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on the following NO_x emission rates:
Combined cycle natural gas firing: 2.0 ppmvd at 15 percent O_2
Combined cycle fuel oil firing: 8.0 ppmvd at 15 percent O_2
Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0075 x (14.4/Y) + F in percent by volume at 15% oxygen and on a dry basis	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference.	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.0 ppmvd at 15% O_2 (combined cycle mode with natural gas firing)	4. Equivalent Allowable Emissions: 17.5 lb/hour 72.3 tons/year
5. Method of Compliance: CEMS.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load for 8,760 hours per year and a site average ambient temperature of 73°F. The equivalent allowable emissions include emissions from HRSG duct burner firing. The allowable emissions from proposed 40 CFR 60, Subpart KKKK are 0.39 lb/MW-hr when firing natural gas, based on a 4-hour rolling average. If this proposed standard becomes final, compliance with the BACT levels will ensure compliance with the proposed standard.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 8.0 ppmvd at 15% O_2 (combined cycle mode with fuel oil firing)	4. Equivalent Allowable Emissions: 81.1 lb/hour 20.3 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load for 500 hours per year and a site minimum ambient temperature of 26°F. The equivalent allowable emissions include emissions from HRSG duct burner firing. The allowable emissions from proposed 40 CFR 60, Subpart KKKK are 1.2 lb/MW-hr when firing fuel oil, based on a 4-hour rolling average. If this proposed standard becomes final, compliance with the BACT levels will ensure compliance with the proposed standard.	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.20 lb/mmBtu (30-day rolling average)	4. Equivalent Allowable Emissions: 113.1 lb/hour 495.2 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart Da and Rule 62-204.800(8)(b).3 - 40 CFR 60, Subpart Da, adopted by reference. The allowable emissions standard apply to the duct burner and are given at 40 CFR 60.44a(a)(1). The equivalent allowable emissions are based on a duct burner heat input rate of 565.3 mmBtu/hr (HHV). This emissions standard applies at all times except during periods of startup, shutdown or malfunction.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 52.0 lb/hour 169.4 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential PM emissions are based on firing fuel oil in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly PM emission rate is 52.0 lb/hour.
The maximum annual potential PM emissions are based on firing fuel oil in the combustion turbine at 100 percent load for 500 hours per year, firing natural gas in the combustion turbine at 100 percent load for the remainder of the year, and firing natural gas in the duct burner for 8,760 hours per year and operation at the site average ambient temperature of 73°F.
Annual emissions = (49.9 lb/hr x 500 hr/yr + 38.0 lb/hr x 8,260 hr/yr) x 1 ton/2,000 lb = 169.4 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on front and back half catch. Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 52.0 lb/hour 169.4 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential PM_{10} emissions are based on firing fuel oil in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly PM_{10} emission rate is 52.0 lb/hour.
The maximum annual potential PM_{10} emissions are based on firing fuel oil in the combustion turbine at 100 percent load for 500 hours per year, firing natural gas in the combustion turbine at 100 percent load for the remainder of the year, and firing natural gas in the duct burner for 8,760 hours per year and operation at the site average ambient temperature of 73°F.
Annual emissions = (49.9 lb/hr x 500 hr/yr + 38.0 lb/hr x 8,260 hr/yr) x 1 ton/2,000 lb = 169.4 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on front and back half catch.
Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 13.6 lb/hour 56.5 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data using natural gas with a sulfur content of 2 grains per 100 scf and ULS fuel oil with a 0.0015 percent sulfur content.
The maximum hourly potential SO_2 emissions are based on firing natural gas in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly SO_2 emission rate is 13.6 lb/hour.
The maximum annual potential SO_2 emissions are based on firing natural gas in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at the site average ambient temperature of 73°F for 8,760 hours per year.
Annual emissions = 12.9 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 56.5 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on using natural gas with a sulfur content of 2 grains per 100 scf. Use of ULS fuel oil (0.0015 percent sulfur) results in lower SO_2 emissions than with natural gas use. The above emission rates do not include the estimated effects of SO_2 oxidation. Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Fuel testing and monitoring will be conducted in accordance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015% sulfur by weight in the fuel oil	4. Equivalent Allowable Emissions: 6.3 lb/hour 1.6 tons/year
5. Method of Compliance: Fuel testing.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions standard given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load for 500 hours per year and a site minimum ambient temperature of 26°F. The equivalent allowable emissions include the effects of firing natural gas in the HRSG duct burner. Excluding the effects of firing natural gas in the HRSG duct burner would result in equivalent allowable emission rates of 3.1 lb/hr and 0.8 tons/year. Meeting this proposed fuel sulfur emissions standard will also ensure compliance with the fuel sulfur standards included in NSPS Subpart GG and in proposed NSPS Subpart KKKK.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 13.6 lb/hour 56.5 tons/year
5. Method of Compliance: Compliance will be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas supplied from the pipeline for each month of operation.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions standard given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load in combined cycle mode and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load in combined cycle mode for 8,760 hours per year and a site average ambient temperature of 73°F. The equivalent allowable emissions include the effects of firing natural gas in the HRSG duct burner. While the natural gas tariff does not guarantee a sulfur content of 2 grains per 100 scf, historical data indicates that this is a reasonable sulfur level. Therefore, if the permit is to include a natural gas sulfur content standard, it is requested that any such standard be based on a calendar month average.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 10.2 lb/hour 23.1 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential emissions are based on operation at 100% load firing fuel oil in the combustion turbine, firing natural gas in the duct burner, and at an ambient temperature of 26°F. The maximum hourly VOC emission rate is 10.2 lb/hour.
The maximum annual potential VOC emissions are based on firing fuel oil in the combustion turbine at 100 percent load for 500 hours per year, firing natural gas in the combustion turbine at 100 percent load for the remainder of the year, and firing natural gas in the duct burner for 8,760 hours per year and operation at the site average ambient temperature of 73°F.
Annual emissions = (9.7 lb/hr x 500 hr/yr + 5.0 lb/hr x 8,260 hr/yr) x 1 ton/2,000 lbs = 23.1 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emission estimates are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.5 lb/hour 22.4 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data using natural gas with a sulfur content of 2 grains per 100 scf and ULS fuel oil with a 0.0015 percent sulfur content. The maximum hourly potential sulfuric acid mist emissions are based on firing natural gas in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at an ambient temperature of 26°F. The maximum hourly sulfuric acid mist emission rate is 5.5 lb/hour. The maximum annual potential sulfuric acid mist emissions are based on firing natural gas in the combustion turbine at 100% load, firing natural gas in the duct burner and operation at the site average ambient temperature of 73°F for 8,760 hours per year. Annual emissions = 5.12 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 22.4 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using natural gas with a sulfur content of 2 grains per scf. Use of ULS fuel oil (0.0015 percent sulfur) results in lower sulfuric acid mist emissions than with natural gas use. Potential emission estimates are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015% sulfur by weight in the fuel oil	4. Equivalent Allowable Emissions: 2.1 lb/hour 0.5 tons/year
5. Method of Compliance: Fuel testing	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are based on the estimated oxidation of SO_2 to SO_3 and assuming 100 percent conversion of SO_3 to sulfuric acid mist. Equivalent allowable emissions are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load for 500 hours per year and a site minimum ambient temperature of 26°F. The equivalent allowable emissions include the effects of firing natural gas in the HRSG duct burner.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 5.5 lb/hour 22.4 tons/year
5. Method of Compliance: Fuel testing	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are based on the estimated oxidation of SO_2 to SO_3 and assuming 100 percent conversion of SO_3 to sulfuric acid mist. Equivalent allowable emissions are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 26°F. The equivalent annual allowable emissions rate is based on operation at 100% load for 8,760 hours per year and a site average ambient temperature of 73°F. The equivalent allowable emissions include the effects of firing natural gas in the HRSG duct burner.	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: CO2 or O2	2. Pollutant(s):
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. B [ ] Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. L [ ] Previously Submitted, Date ________

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. M [ ] Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. N [ ] Previously Submitted, Date ________
[ ] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[x] Attached, Document ID: Attach. O [ ] Previously Submitted, Date ________
[ ] Not Applicable

6. Compliance Demonstration Reports/Records
[ ] Attached, Document ID: ________
Test Date(s)/Pollutant(s) Tested: ________

[ ] Previously Submitted, Date: ________
Test Date(s)/Pollutant(s) Tested: ________

[ ] To be Submitted, Date (if known): ________
Test Date(s)/Pollutant(s) Tested: ________

[x] Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
[ ] Attached, Document ID: ________ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: Attach. P ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: Attach. Q ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: Attach. R ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ________	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ________ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ________ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ________ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Auxiliary Boiler.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes [x] No

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 7.2 mmBtu/hr (estimate)		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: The maximum heat input rate given in Field 3 is an estimate. The actual maximum heat input rate will be dependent on the chosen vendor.		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Auxiliary Boiler	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 25 feet	7. Exit Diameter: 1.3 feet
8. Exit Temperature: 525°F	9. Actual Volumetric Flow Rate: 2,600 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.5523 North (km): 3028.9614	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected emission unit parameters. A specific auxiliary boiler model has not been chosen yet.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Natural gas used in the auxiliary boiler		
2. Source Classification Code (SCC): 10100602	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.0074	5. Maximum Annual Rate: 64.8	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 970 (HHV)
10. Segment Comment:		

Segment Description and Rate: Segment _ of _

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			**NS**
NOX			**NS**
PM			**NS**
PM10			**NS**
SO2			**NS**
VOC			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.52 lb/hour 2.28 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 0.52 lb/hour. The maximum annual potential CO emissions are based on operation for 8,760 hours per year. Annual emissions = 0.52 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 2.28 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.26 lb/hour 1.14 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly NO_x emission rate is 0.26 lb/hour.
The maximum annual potential NO_x emissions are based on operation for 8,760 hours per year.
Annual emissions = 0.26 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 1.14 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.03 lb/hour 0.13 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM emission rate is 0.03 lb/hour. The maximum annual potential PM emissions are based on operation for 8,760 hours per year. Annual emissions = 0.03 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 0.13 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.03 lb/hour 0.13 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM_{10} emission rate is 0.03 lb/hour. The maximum annual potential PM_{10} emissions are based on firing operation for 8,760 hours per year. Annual emissions = 0.03 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 0.13 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.04 lb/hour 0.18 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data and using natural gas with a sulfur content of 2 grains per 100 scf. The maximum hourly SO_2 emission rate is 0.04 lb/hour. The maximum annual potential SO_2 emissions are based on operation for 8,760 hours per year. Annual emissions = 0.04 lb/hr x 8,760 hours/year x 1 ton/2,000 lb = 0.18 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using natural gas with a sulfur content of 2 grains per 100 scf. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.04 lb/hour 0.18 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly VOC emission rate is 0.04 lb/hour.
The maximum annual potential VOC emissions are based on operation for 8,760 hours per year.
Annual emissions = 0.04 lb/hr x 8,760 hours/year x 1 ton/2,000 lbs = 0.18 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of ___

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: USEPA Method 9 visual determination of opacity	
5. Visible Emissions Comment: Rule 62-296.406, F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. L ☐ Previously Submitted, Date ______
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______
   [x] Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. O ☐ Previously Submitted, Date ______
   ☐ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ______
   Test Date(s)/Pollutant(s) Tested: ______

   ☐ Previously Submitted, Date: ______
   Test Date(s)/Pollutant(s) Tested: ______

   ☐ To be Submitted, Date (if known): ______
   Test Date(s)/Pollutant(s) Tested: ______

   [x] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ______ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: Attach. P ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: Attach. Q ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID:__________ [X] Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: __________	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: __________ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: __________ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: __________ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Diesel Engine Fire Pump.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes [x] No

9. Package Unit:
   Manufacturer: TBD   Model Number: TBD

10. Generator Nameplate Rating:

11. Emissions Unit Comment: The diesel engine fire pump is considered emergency equipment and as such is considered exempt from permitting in accordance with Rule 62-210.300(3). While this emissions unit is exempt from permitting its' emissions are still included in the potential to emit for the Project and in the AQIA and this Emissions Unit Information Section is used to provide information on the Diesel Engine Fire Pump.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: 300 HP (approximate)	
3. Maximum Heat Input Rate:	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year	 7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: Based on National Fire Protection Association (NFPA) guidelines it is conservatively estimated that the diesel engine fire pump will operate approximately 200 hours per year. Because this is emergency fire equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Fire Pump Building	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: V	6. Stack Height: 29 feet	7. Exit Diameter: 0.835 feet
8. Exit Temperature: 708°F	9. Actual Volumetric Flow Rate: 2,150 acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.4285 North (km): 3028.9605	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Fuel oil used in the diesel engine fire pump		
2. Source Classification Code (SCC): 20100301	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 0.0166	5. Maximum Annual Rate: 3.32	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 200 hours per year of operation.		

Segment Description and Rate: Segment _ of _

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			**NS**
NOX			**NS**
PM			**NS**
PM10			**NS**
SO2			**NS**
VOC			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 1.2 lb/hour 0.12 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly CO emission rate is 1.2 lb/hour.
The maximum annual potential CO emissions are based on operating 200 hours per year.
Annual emissions = 1.2 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.12 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.9 lb/hour 0.59 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly NO_x emission rate is 5.9 lb/hour.
The maximum annual potential NO_x emissions are based on operating 200 hours per year.
Annual emissions = 5.9 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.59 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.11 lb/hour 0.01 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM emission rate is 0.11 lb/hour. The maximum annual potential PM emissions are based on operating 200 hours per year. Annual emissions = 0.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.01 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.11 lb/hour 0.01 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly PM_{10} emission rate is 0.11 lb/hour.
The maximum annual potential PM_{10} emissions are based on operating 200 hours per year.
Annual emissions = 0.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.01 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.003 lb/hour 0.0003 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content.
The maximum hourly SO_2 emission rate is 0.003 lb/hour.
The maximum annual potential SO_2 emissions are based on operating 200 hours per year.
Annual emissions = 0.003 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.0003 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.21 lb/hour 0.02 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.21 lb/hour. The maximum annual potential VOC emissions are based on operating 200 hours per year. Annual emissions = 0.21 lb/hr x 200 hours/year x 1 ton/2,000 lbs = 0.02 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. L ☐ Previously Submitted, Date ________

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. O ☐ Previously Submitted, Date ________
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________________________

   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________________________

   ☐ To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: Attach. P	[ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: Attach. Q	[ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:___________	[x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements [ ] Attached, Document ID: ___________	
2. Compliance Assurance Monitoring [ ] Attached, Document ID: __________	[ ] Not Applicable
3. Alternative Methods of Operation [ ] Attached, Document ID: __________	[ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: __________	[ ] Not Applicable

5. Acid Rain Part Application
   - [ ] Certificate of Representation (EPA Form No. 7610-1)
     - [ ] Copy Attached, Document ID:_
   - [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
     - [ ] Attached, Document ID:___________
     - [ ] Previously Submitted, Date:_________
   - [ ] Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Safe Shutdown Generator.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	[ ] Yes [x] No

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate: 765 HP (approximate)		
3. Maximum Heat Input Rate:		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: It is conservatively estimated that the safe shutdown generator will operate approximately 200 hours per year. Because this is emergency equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Safe Shutdown Generator	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 11 feet	7. Exit Diameter: 0.665 feet
8. Exit Temperature: 981°F	9. Actual Volumetric Flow Rate: 3920 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.5347 North (km): 3028.9730	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Fuel oil used in the safe shutdown generator			
2. Source Classification Code (SCC): 20100301		3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 0.0363	5. Maximum Annual Rate: 7.26		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 200 hours per year of operation.			

Segment Description and Rate: Segment _ of _

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			NS
NOX			NS
PM			NS
PM10			NS
SO2			NS
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.89 lb/hour 0.09 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 0.89 lb/hour. The maximum annual potential CO emissions are based on operating 200 hours per year. Annual emissions = 0.89 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.09 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 11.3 lb/hour 1.13 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly NO_x emission rate is 11.3 lb/hour. The maximum annual potential NO_x emissions are based on operating 200 hours per year. Annual emissions = 11.3 lb/hr x 200 hours/year x 1 ton/2,000 lb = 1.13 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.08 lb/hour 0.01 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM emission rate is 0.08 lb/hour. The maximum annual potential PM emissions are based on operating 200 hours per year. Annual emissions = 0.08 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.01 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.08 lb/hour 0.01 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM_{10} emission rate is 0.08 lb/hour. The maximum annual potential PM_{10} emissions are based on operating 200 hours per year. Annual emissions = 0.08 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.01 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.008 lb/hour 0.001 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content.
The maximum hourly SO_2 emission rate is 0.008 lb/hour.
The maximum annual potential SO_2 emissions are based on operating 200 hours per year.
Annual emissions = 0.008 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.001 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.11 lb/hour 0.01 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.11 lb/hour. The maximum annual potential VOC emissions are based on operating 200 hours per year. Annual emissions = 0.11 lb/hr x 200 hours/year x 1 ton/2,000 lbs = 0.01 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. L ☐ Previously Submitted, Date ______

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______
   [x] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. O ☐ Previously Submitted, Date ______
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ______
   Test Date(s)/Pollutant(s) Tested: ______

   ☐ Previously Submitted, Date: ______
   Test Date(s)/Pollutant(s) Tested: ______

   ☐ To be Submitted, Date (if known): ______
   Test Date(s)/Pollutant(s) Tested: ______

   [x] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ______ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: Attach. P	[ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: Attach. Q	[ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:___________	[x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements [ ] Attached, Document ID: ___________	
2. Compliance Assurance Monitoring [ ] Attached, Document ID: __________	[ ] Not Applicable
3. Alternative Methods of Operation [ ] Attached, Document ID: __________	[ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: __________	[ ] Not Applicable
5. Acid Rain Part Application [ ] Certificate of Representation (EPA Form No. 7610-1) [ ] Copy Attached, Document ID:_ [ ] Acid Rain Part (Form No. 62-210.900(1)(a)) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Fuel Oil Storage Tank.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	☐ Yes [x] No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment: The capacity of the Fuel Oil Storage Tank is slightly less than 990,000 gallons. In accordance with Rule 62-210.300(3)(b)1., F.A.C., the fuel oil storage tank is exempt from the requirement to obtain an air construction permit. However, the fuel oil storage tank VOC emissions were included in the Project potential to emit estimates and this Emissions Unit Information section is used to provide information on the fuel oil storage tank.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 6,850,000 gallons per year	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate:	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Fuel oil tank		2. Emission Point Type Code: 4
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Fuel oil storage tank.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: F	6. Stack Height:	7. Exit Diameter:
8. Exit Temperature: 77 F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: 40 ft
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.8163 North (km): 3028.9551		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Breathing loss		
2. Source Classification Code (SCC): 2501000090	3. SCC Units: Thousand Gallons Stored	
4. Maximum Hourly Rate: 0	5. Maximum Annual Rate: 0	6. Estimated Annual Activity Factor: 1,000
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Working loss		
2. Source Classification Code (SCC): 2501000090	3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: 6,850	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.04 lb/hour 0.16 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: USEPA TANKS Program	7. Emissions Method Code: 3
8. Calculation of Emissions: Potential emissions are based on use of the USEPA TANKS program. The maximum annual VOC emission rate is 323.1 lb/year = 0.16 tons/year. The TANKS program gives the VOC emissions in lbs per year rather than lbs per hour. The annual emissions were spread out evenly over the entire year to obtain a lbs per hour value. The hourly VOC emission rate is 0.04 lb/hour.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: NA ☐ Previously Submitted, Date ________
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: NA ☐ Previously Submitted, Date ________
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Attach. O ☐ Previously Submitted, Date ________
   ☐ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________________

   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________________

   ☐ To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID:___________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID:___________ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID:___________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___________
2. Compliance Assurance Monitoring ☐ Attached, Document ID: __________ ☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: __________ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: __________ ☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [x] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Mechanical Draft Cooling Tower.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes [x] No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Drift eliminators
2. Control Device or Method Code(s): 152

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 111,130 gpm design water flow		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Cooling Tower	2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 46 ft	7. Exit Diameter: 32 ft
8. Exit Temperature: 95 F	9. Actual Volumetric Flow Rate: 1,000,000 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 561.5163 North (km): 3029.0521	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The cooling tower design is an 8 cell mechanical draft cooling tower. The information given in fields 5 through 9 is for each cell.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Drift loss		
2. Source Classification Code (SCC): 38500101	3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate: 6,670	5. Maximum Annual Rate: 58,409,928	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: The maximum hourly and annual rates shown in Fields 4 and 5 are the design water circulation rate.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			**WS**
PM10			**WS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 1.48 lb/hour 6.48 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data, mass balance	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on the design cooling tower water flow, the design drift rate and the cycled water total dissolved solids. Design water flow = 111,130 gpm = 55,609,452 lb/hr Design drift rate = 0.0005% of design water flow Total dissolved solids = 5,331 ppm Hourly PM emissions = 55,542,774 lb/hr x 0.0005/100 x 5,331 ppm/1,000,000 = 1.48 lb/hr The maximum annual PM emissions = 1.48 lb/hr x 8,760 hr/yr x ton/2,000 lb = 6.48 tpy	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.43 lb/hour 1.87 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:

Potential emissions are based on the design cooling tower water flow, the design drift rate, the cycled water total dissolved solids, and the percent of PM that is PM_{10}. The maximum PM_{10} emissions occur when the cycled water total dissolved solids is 3,918 ppm. At this total dissolved solids value the percent of PM that is PM_{10} is equal to 39.14 percent.

Design water flow = 111,130 gpm = 55,542,774 lb/hr
Design drift rate = 0.0005 percent of design water flow
Total dissolved solids = 3,918 ppm
Percent of PM that is PM_{10} = 39.14 percent
Hourly PM_{10} emissions = 55,542,774 lb/hr x 0.0005% x 3,918 ppm/1,000,000 x 39.14% = 0.426 lb/hr
The maximum annual PM_{10} emissions = 0.426 lb/hr x 8,760 hr/yr x ton/2,000 lb = 1.87 tpy

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

<u>Continuous Monitoring System:</u> Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

<u>Continuous Monitoring System:</u> Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. B [ ] Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: NA [ ] Previously Submitted, Date ________

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. M [ ] Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ________ [ ] Previously Submitted, Date ________
   [x] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. O [ ] Previously Submitted, Date ________
   [ ] Not Applicable

6. Compliance Demonstration Reports/Records
   [ ] Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________________

   [ ] Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________________

   [ ] To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________________

   [x] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   [ ] Attached, Document ID: ________ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: Attach. P [ ] Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [ ] Attached, Document ID:_________ [ ] Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:___________ [x] Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements [ ] Attached, Document ID: ___________	
2. Compliance Assurance Monitoring [ ] Attached, Document ID: __________ [ ] Not Applicable	
3. Alternative Methods of Operation [ ] Attached, Document ID: __________ [ ] Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: __________ [ ] Not Applicable	
5. Acid Rain Part Application [ ] Certificate of Representation (EPA Form No. 7610-1) [ ] Copy Attached, Document ID:_ [ ] Acid Rain Part (Form No. 62-210.900(1)(a)) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:________ [ ] Not Applicable	

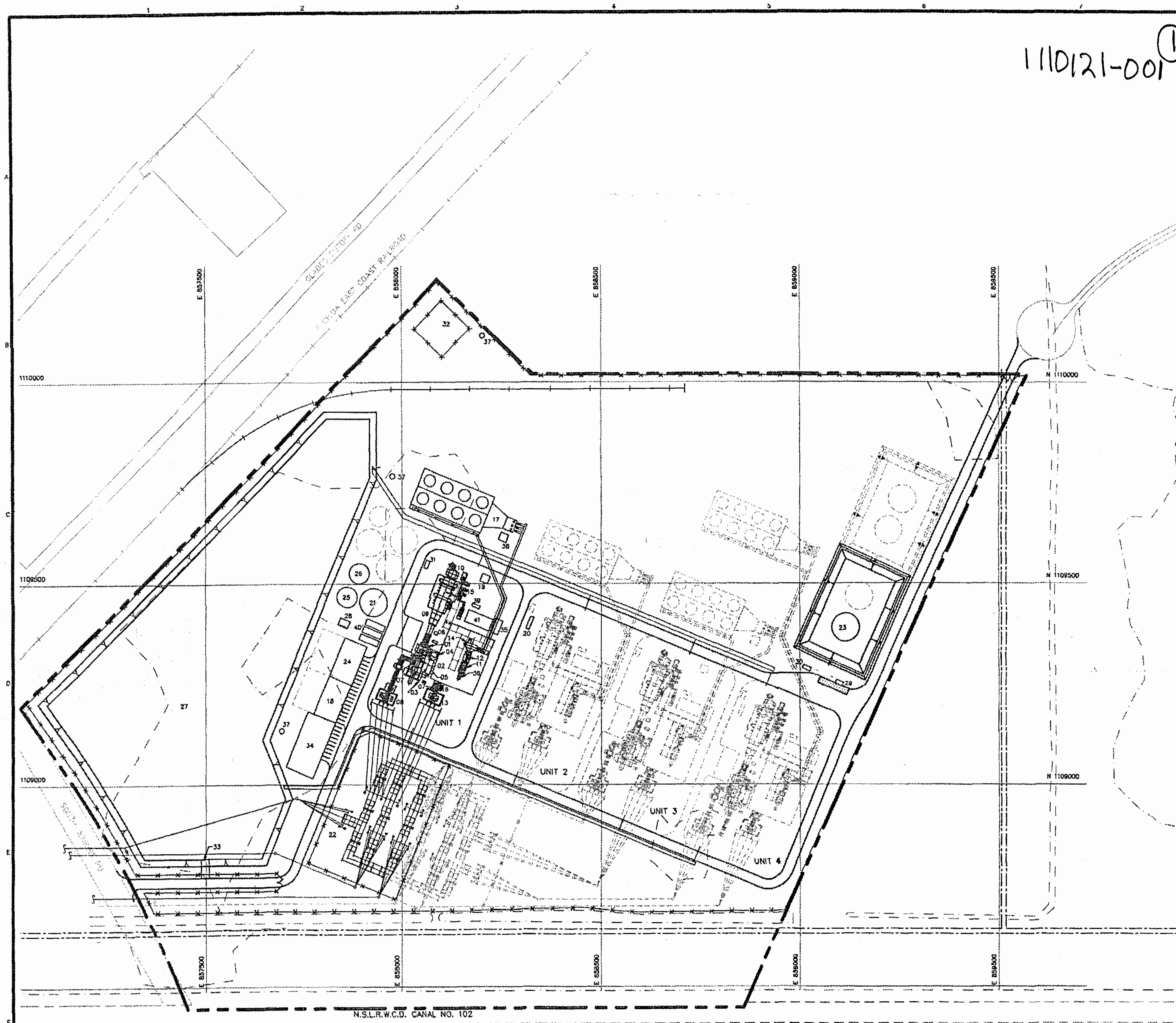
Additional Requirements Comment

Attachment A

Facility Plot Plan

BEST AVAILABLE COPY

1110121-001 (1)



FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
01	COMBUSTION TURBINE	–	–	–	
02	COMBUSTION TURBINE GENERATOR	–	–	–	
03	COMBUSTION TURBINE INLET AIR FILTER	–	–	–	
04	COMBUSTION TURBINE ACCESSORY MODULE	–	–	–	
05	COMBUSTION TURBINE ELECTRICAL PACKAGE	–	–	–	
06	COMBUSTION TURBINE WASH WATER SKID	–	–	–	
07	ISOLATED PHASE BUS DUCT	–	–	–	
08	CT GENERATOR STEPUP TRANSFORMER	–	–	–	
09	HEAT RECOVER STEAM GENERATOR	–	–	–	
10	HEAT RECOVERY STEAM GENERATOR EXHAUST STACK	–	–	–	
11	STEAM TURBINE	–	–	–	
12	STEAM TURBINE GENERATOR	–	–	–	
13	STEAM TURBINE GENERATOR STEPUP TRANSFORMER	–	–	–	
14	CONDENSER	–	–	–	
15	BOILER FEED PUMPS	–	–	–	
16	GENERATOR BREAKER	–	–	–	
17	COOLING TOWER	–	–	–	
18	ADMINISTRATION BUILDING/CONTROL ROOM	–	–	–	
19	WASTEWATER COLLECTION SUMP	–	–	–	
20	OIL/WATER SEPARATOR	–	–	–	
21	DEMINERALIZED WATER TANK	–	–	–	
22	SUBSTATION	–	–	–	
23	FUEL OIL TANK	–	–	–	
24	WATER TREATMENT BUILDING	–	–	–	
25	FIRE PROTECTION/SERVICE WATER TANK	–	–	–	
26	FIRE PROTECTION/SERVICE WATER TANK	–	–	–	
27	DETENTION POND	–	–	–	
28	FIRE PUMP BUILDING	–	–	–	
29	FUEL OIL UNLOADING PUMPS	–	–	–	
30	FUEL FORWARDING SKID	–	–	–	
31	AMMONIA STORAGE TANK	–	–	–	
32	GAS METERING STATION	–	–	–	
33	DETENTION BASIN DISCHARGE	–	–	–	
34	WAREHOUSE	–	–	–	
35	AUXILIARY BOILER	–	–	–	
36	STEAM TURBINE GENERATOR ROTOR REMOVAL	–	–	–	
37	PRODUCTION WELL	–	–	–	
38	CHEMICAL FEED BUILDING	–	–	–	
39	SAFE SHUTDOWN DIESEL GENERATOR	–	–	–	
40	DEMINERALIZED WATER TRAILERS	–	–	–	
41	ELECTRICAL EQUIPMENT BUILDING	–	–	–	

GENERAL LEGEND

- PROPERTY BOUNDARY
- FUTURE UNIT
- WETLAND BOUNDARY
- TRANSMISSION LINES
- UTILITY EASEMENT
- FENCING
- CANAL
- RAIL
- ASPHALT SURFACING
- CONCRETE SURFACING
- AGGREGATE SURFACING

NOTES

FOR PERMITTING PURPOSE ONLY
APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE
0	04/08/05	ISSUED FOR CONSTRUCTION

SCALE: 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA

SIGNED ______
DATE ______ REG NO. ______

BLACK & VEATCH CORPORATION

FMPA
TREASURE COAST ENERGY CENTER UNIT 1

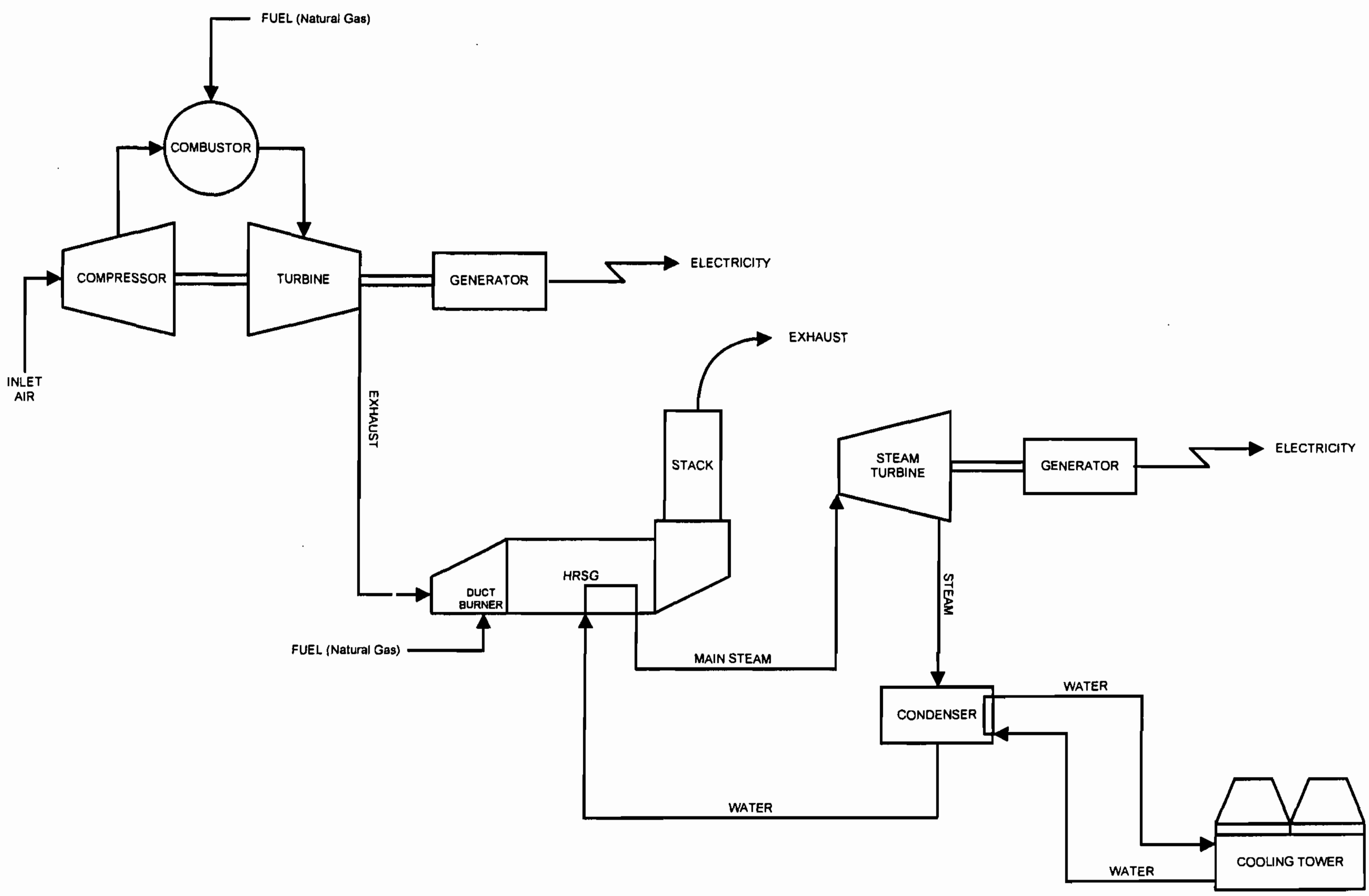
ULTIMATE SITE ARRANGEMENT

DRAWN MSW DATE 04/08/05

PROJECT / DRAWING NUMBER: 138859-CSTA-S1001 REV 0

Attachment B

Process Flow Diagram



Treasure Coast Energy Center
Combined Cycle Combustion Turbine
Process Flow Diagram

Attachment C

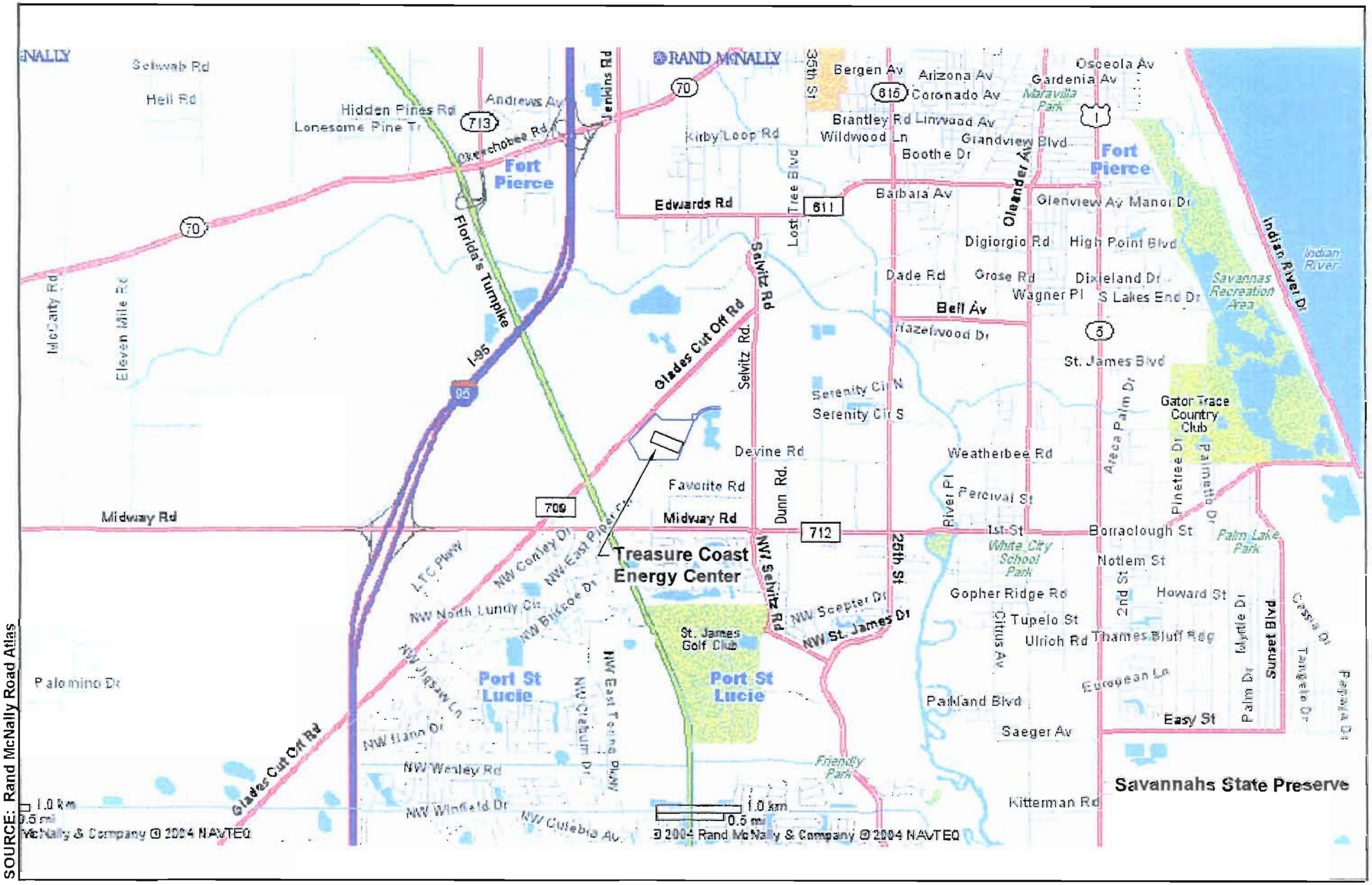
Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

Reasonable precautions to control unconfined emissions of particulate matter as listed in Rule 62-296.320(4), FAC will be employed as appropriate. Additionally, watering will be used as needed to prevent emissions from unpaved areas.

Attachment D

Area Map Showing Facility Location



SOURCE: Rand McNally Road Atlas

BLACK & VEATCH CORPORATION

1 1/2 0 1
SCALE IN MILES

TREASURE COAST ENERGY CENTER

PROPOSED PROJECT LOCATION

FIGURE 2-1

Attachment E

Description of Proposed Construction or Modification

Description of Proposed Construction or Modification

The Florida Municipal Power Agency (FMPA) proposes to install a 1x1 F-Class Combined Cycle Unit (Project) at the new Treasure Coast Energy Center, near Fort Pierce, St. Lucie County, Florida. The Project will include a 1x1 combined cycle unit (Unit 1) which will include a combustion turbine generator (CTG), heat recovery steam generator (HRSG), and a steam turbine generator (STG), operating at a nominal rating of 300 MW. New major support facilities include an approximately 990,000 gallon fuel oil storage tank, a natural gas fired auxiliary boiler, a diesel engine driven fire pump and associated 500 gallon fuel oil storage tank, a safe shutdown diesel generator and associated 1,000 gallon fuel oil storage tank, and a mechanical draft cooling tower. A more detailed description of the proposed construction can be found in the application technical support document accompanying this application.

Attachment F

Rule Applicability Analysis

Rule Applicability Analysis

Rule Applicability Analysis for the Entire Facility

State: Rule 62-4.070 – Standards for Issuing or Denying Permits.

State: Rule 62-210.300 – Permits Required.

State: Rule 62-212.300 – General Preconstruction Review Requirements.

State: Rule 62-212.400 – Prevention of Significant Deterioration.

Rule Applicability Analysis for the GE 7FA Combined Cycle Combustion Turbine

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart YYYY, *National Emission Standards for Stationary Combustion Turbines*. This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the Treasure Coast Energy Center will not be a major source of HAPs, 40 CFR 63 Subpart YYYY does not apply to the combustion turbine.

May Become Applicable - Federal: 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Gas Turbines* – Proposed Rule Published in the Federal Register on February 18, 2005. When/if this proposed rule becomes final as published it will apply to Unit 1.

The following rules are applicable to the Combined Cycle Combustion Turbine:

Federal: 40 CFR Part 60 Subpart GG (Rule 62-204.800(8)(b).39) – *Standards of Performance for Stationary Gas Turbines.* If/when proposed NSPS Subpart KKKK published in the Federal Register on February 18, 2005 becomes final as proposed, because Unit 1 would become subject to Subpart KKKK, it would not be subject to Subpart GG.

Federal: 40 CFR Part 60 Subpart Da (Rule 62-204.800(8)(b).39) – *Standards of Performance for Electric Utility Steam Generators for Which Construction is Commenced After September 18, 1978.* If/when proposed NSPS Subpart KKKK published in the Federal Register on February 18, 2005 and proposed revisions to Subpart Da published in the Federal Register on February 28, 2005 become final as proposed, because the duct burner would be covered under Subpart KKKK, it would not be subject to Subpart Da.

Federal: 40 CFR Part 60 Subpart A – *General Provisions.*

Federal: 40 CFR Part 72 – *Permits Regulation (Acid Rain)*

Federal: 40 CFR Part 75 – *Continuous Emissions Monitoring*

State: Rule 62-204.800(8)(d) – *General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions.*

State: Rule 62-212.400 – *Prevention of Significant Deterioration* applies to CO, NO_x, SO_2, PM, PM_{10}, and sulfuric acid mist. See the technical support document accompanying this application for a more detailed discussion of PSD applicability.

State: Rule 62-212.300 – *General Preconstruction Review Requirements.* Applies to applicable pollutants not subject to PSD review.

State: Rule 62-297.310 – *General Compliance Test Requirements.*

Rule Applicability Analysis for the Natural Gas Auxiliary Boiler

NOT APPLICABLE - Federal: 40 CFR Part 60 Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.* This standard applies to each steam generating unit that has a maximum design capacity of 100 mmBtu/hr or less, but greater than 10 mmBtu/hr. Because the Project natural gas auxiliary boiler has a maximum heat input rate of less than 10 mmBtu/hr, it is not subject to 40 CFR 60 Subpart Dc.

The following rules are applicable to the Natural Gas Auxiliary Boiler:

State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

State: Rule 62-296.406, F.A.C., *Fossil Fuel Steam Generators with Less Than 250 Million Btu Per Hour Heat Input, New and Existing Units.*

State: Rule 62-297.310 – *General Compliance Test Requirements.*

Rule Applicability Analysis for the Diesel Engine Fire Pump

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Recipricating Internal Combustion Engines.* This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the Treasure Coast Energy Center will not be a major source of HAPs, 40 CFR 63 Subpart ZZZZ does not apply to the diesel engine fire pump.

The following rules are applicable to the Diesel Engine Fire Pump:
State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

Rule Applicability Analysis for the Safe Shutdown Diesel Generator

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Recipricating Internal Combustion Engines.* This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the Treasure Coast Energy Center will not be a major source of HAPs, 40 CFR 63 Subpart ZZZZ does not apply to the safe shutdown diesel generator.

The following rules are applicable to the Safe Shutdown Diesel Generator:
State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

Rule Applicability Analysis for the 990,000 Gallon No. 2 Fuel Oil Storage Tank

NOT APPLICABLE - Federal: 40 CFR Part 60 Subpart Kb, AS REVISED OCTOBER 15, 2003 – *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.* Because the vapor pressure of No. 2 fuel oil is less than 3.5 kPa, this storage tank is not subject to 40 CFR Part 60 Subpart Kb.

NOT APPLICABLE - State: Rule 62-212.300 – *General Preconstruction Review Requirements.* Per 62-210(3), F.A.C., this emissions unit is exempt from the permitting requirements of Chapter 62-212, F.A.C. because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1., F.A.C.

Attachment G

List of Exempt Emission Units

List of Exempt Emission Units

The 990,000 gallon fuel oil storage tank is exempt from the requirement to obtain an air construction permit. The unit is exempt in accordance with Rule 62-210.300(3)(b)1., F.A.C.

The Diesel Engine Fire Pump is exempt from the requirement to obtain an air construction permit. The unit is exempt in accordance with Rule 62-210.300(3)(a)22., F.A.C.

Attachment H

Preconstruction Air Quality Monitoring and Analysis

Preconstruction Air Quality Monitoring and Analysis

Preconstruction air quality monitoring is addressed in Section 4.0 of the technical support document included with this application.

Attachment I

Ambient Impact Analysis

Ambient Impact Analysis

The ambient impact analysis is included as Section 4.0 of the technical support document included with this application.

Attachment J

Air Quality Impact Since 1977

Air Quality Impact Since 1977

A discussion of the Air Quality Impact since 1977 is included in Section 5 of the technical support document included with this application.

Attachment K

Additional Impact Analyses

Additional Impact Analyses

Additional Impact Analyses are included in Section 5 of the technical support document included with this application.

Attachment L

Fuel Analysis or Specification

Fuel Analysis or Specification

Fuel is specified as pipeline natural gas or No. 2 fuel oil containing no more than 0.0015 percent sulfur.

Attachment M

Detailed Description of Control Equipment

Detailed Description of Control Equipment

Dry Low-NO_x Burners: Dry low-NO_x burners are used to reduce flame temperature as a means to control NO_x emissions. A more detailed discussion of dry low-NO_x burners is included in Attachment 4 of the application support document.

Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emissions is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. A more detailed discussion of water injection is included in Attachment 4 of the application support document.

Selective Catalytic Reduction (SCR): A post-combustion control technology used to limit NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. A more detailed discussion of the SCR control system is included in Attachment 4 of the application support document.

Drift Eliminators: The mechanical draft cooling tower will include drift eliminator to achieve a design drift rate of 0.0005 percent, thus minimizing PM and PM_{10} emissions.

Attachment N

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

Procedures for startup and shutdown will be completed in accordance with manufacturers' operating procedures and/or plant operating procedures.

Attachment O

Operation and Maintenance Plan

Operation and Maintenance Plan

The emission units will be operated and maintained in accordance with manufacturer's recommendations, operations and maintenance experience, and technical guidance taking into account protection of equipment, safety of personnel and other factors as deemed necessary to maintain compliance with the permitted limits.

Attachment P

Control Technology Review and Analysis

Control Technology Review and Analysis

The control technology review and analysis is included as Attachment 4 of the application support document included with this application.

Attachment Q

Good Engineering Practice Stack Height Analysis

Good Engineering Practice Stack Height Analysis

A good engineering practice stack height analysis is included in Section 4.2.3 of the application support document included with this application.

Attachment R

Description of Stack Sampling Facilities

Description of Stack Sampling Facilities

Unit 1 will be equipped with stack sampling facilities appropriate for performing required stack testing. A detailed description of stack sampling facilities is not available at this time. When available, if requested by the Department, the stack sampling facilities description will be supplied to the Department.

Attachment S

Air Dispersion Modeling Files (CD)


Treasure Coast Energy Center
Unit 1
Florida Power Plant
Siting Act
Site Certification
Application
Prevention of
Significant
Deterioration
Air Permit Application
Class I and Class II
Air Dispersion Modeling Files
April 2005