Florida Electrical Power Plant Siting Act
Site Certification Application

Prevention of Significant Deterioration
Air Permit Application

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Volume 3 of 3

Greenland Energy Center
Combined Cycle Conversion Project

JEA®
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September 2008

JEA – Greenland Energy Center
Units 1 and 2
Combined Cycle Conversion

Prevention of Significant Deterioration
Air Permit Application

September 2008

Prepared for:
JEA
Jacksonville, Florida

Prepared by:
Black & Veatch
Overland Park, Kansas

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Acronym List

AERMIC	AMS/EPA Regulatory Model Improvement Committee
AMS/EPA	American Meteorological Society/Environmental Protection Agency
AQIA	Air Quality Impact Analysis
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
bhp	Brake Horsepower
BPIPPRM	Building Profile Input Program Prime
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CALPUFF	California Puff
CAMR	Clean Air Mercury Rule
CCCT	Combined Cycle Combustion Turbine
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CIPP	Cane Island Power Park
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
CWA	Chassahowitzka Wilderness Area
DAT	Deposition Analysis Threshold
DEM	Digital Elevation Model
DLN	Dry Low NO_x Burner
dv	Deciview
EC	Elemental Carbon
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FDEP	Florida Department of Environmental Protection
FWS	Fish and Wildlife Service
GE	General Electric
GEP	Good Engineering Practice
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid Mist
ha	Hectares
HAP	Hazardous Air Pollutant
Hg	Mercury
hr	Hour

HRSG	Heat Recovery Steam Generator
ISO	International Organization for Standardization
IWAQM	Interagency Workgroup on Air Quality Modeling
kgal/yr	Kilo gallons (or 1,000 gallons) per year
kW	Kilowatt
lb/h	Pound per Hour
LCC	Lambert Conformal Conic
MBtu	Million British Thermal Unit
MSA	Metropolitan Statistical Area
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	Nanogram per Joule
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O3	Ozone
Pb	Lead
PM/PM10	Particulate Matter/Particulate Matter Less than 10 Microns
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
psig	Pounds Per Square Inch Gauge
PTE	Potential To Emit
RICE	Reciprocating Internal Combustion Engines
RH	Relative Humidity
rpm	Revolutions Per Minute
scf	Standard Cubic Feet
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
GEC	Greenland Energy Center
SER	Significant Emission Rates
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SOA	Secondary Organic Aerosols
STG	Steam Turbine Generator

tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	Volatile Organic Compound
vr	Visual Range
WGS	World Geodetic System
yr	Year

1.0 Introduction

JEA proposes to convert the two proposed simple cycle combustion turbines (CTs) at the Greenland Energy Center (GEC) into a 2 x 1 combined cycle configuration (hereinafter referred to as the Project). The GEC is located in southeastern Duval County, Florida and is currently undergoing construction permitting for the two simple cycle units. The combined cycle configuration will consist of the same two General Electric (GE) 7FA combustion turbines that are currently being permitted as simple cycle units, but will now each include a heat recovery steam generator with supplemental natural gas-fired duct burners exhausting to one steam turbine generator. The simple cycle functionality of each combustion turbine will be retained post-combined cycle conversion. The currently proposed simple cycle combustion turbine stack will function as a bypass stack when the combustion turbines are operating in a simple cycle mode. An eight-cell linear mechanical draft cooling tower (LMDCT) will also be constructed as part of the proposed Project. The proposed Project will include only the combined cycle conversion of the simple cycle units, including the cooling tower, with no further additions to the ancillary units already included as part of the simple cycle operations. However, these ancillary units will be included in the modeling demonstration for the combined cycle conversion.

Florida Department of Environmental Protection (FDEP) has requested that JEA submit the air permit application for the combined cycle conversion as if the Project were initially planned for and designed as a combined cycle facility rather than as a modification to the simple cycle facility with associated increases in emissions. To that end, JEA anticipates that the potential emissions of the combined cycle conversion will trigger air permitting review requirements under the Prevention of Significant Deterioration (PSD) program of Florida Regulation 62-212.400.

2.0 Project Characterization

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

2.1 Project Location

The GEC is located in southeastern Duval County, in the City of Jacksonville. Duval County is classified as an attainment area for all criteria air pollutants. The average site elevation is 30 feet and the terrain surrounding the site is flat. The approximate UTM coordinates of the site are 450,266 m East and 3,336,445 m North (Zone 17, NAD 27). The site location is shown in Figure 2-1.

2.2 Description of Equipment and Emission Units

The major combustion equipment at the GEC post-combined cycle conversion will consist of two CTGs, each having the capability to fire both natural gas and ULSFO, and a heat recovery steam generator (HRSG) with natural gas fired duct-burners. Emissions control equipment will consist of a selective catalytic reduction (SCR) system, dry low NO_x (DLN) combustors while firing natural gas, and a combination of DLN combustors with water injection in the CTGs for NO_x control during ULSFO combustion. The Project consists of the following major pieces of equipment:

- Two GE 7FA CTGs capable of firing natural gas or ULSFO
- Natural gas fired duct burners in each HRSG.
- One steam turbine generator
- One eight-cell LMDCT

The following equipment have been considered in the simple cycle project and will not be modified as part of this application package.

- One 350 brake horsepower (bhp) emergency diesel fire pump used as a backup for emergency water supply, including a 500 gallon ULSFO day tank (already permitted in the Simple Cycle Project)
- One 1,500 kW emergency diesel engine generator with a 2,500 gallon ULSFO day tank (Already permitted in the simple cycle project)
- One 5.84 MBtu/h natural gas fired fuel gas heater.
- Two 1.875 million-gallon ULSFO storage tanks.

The site arrangement of the Project is presented on Appendix A. Table 2-1 summarizes the emission units and corresponding operating limits in this application.

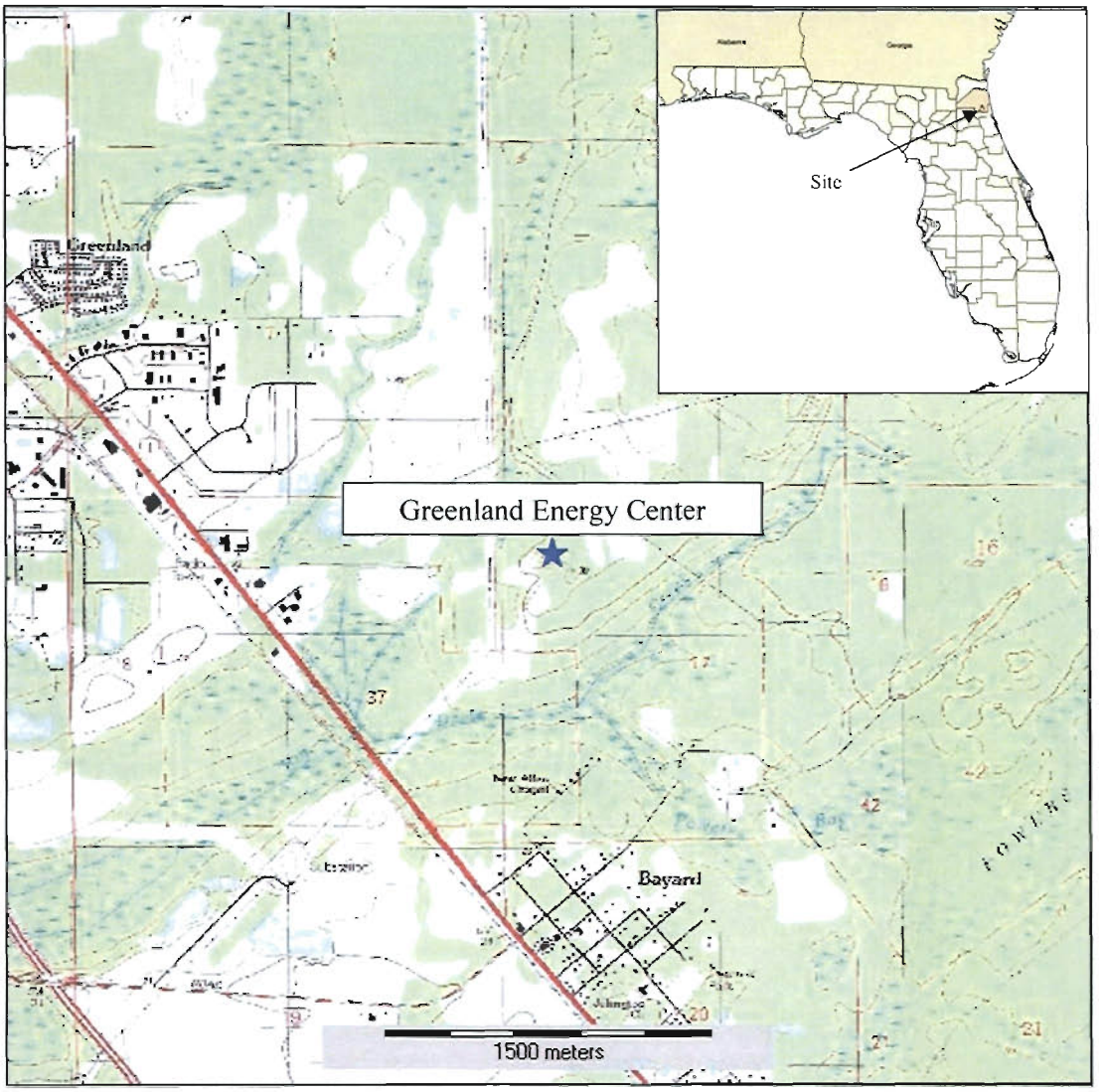

Figure 2-1
Area Map and Proposed Project Location

2.2.1 Combustion Turbines

This application is based on installation of two GE 7FA CTGs operating in simple cycle mode. Each CTG will include the following major features:

- Dual fuel firing system using natural gas or ULSFO.
- Dry low NO_x combustion system for NO_x reduction when firing natural gas, and water injection while firing ULSFO.
- Static inlet air filtration.
- Mark VI control system.

The fuel for GEC will be natural gas and ULSFO (0.0015 percent sulfur or 15 ppm sulfur). Natural gas will be delivered to the site by a new pipeline. ULSFO delivery will be by truck. No new storage tanks will be constructed. A truck unloading and transfer station along with two 1.875 million gallon ULSFO storage tanks is proposed to be constructed as part of the simple cycle project.

2.2.2 Heat Recovery Steam Generator

Each 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 (189 MBtu/h) by natural gas only to maximize unit output. Selective catalytic reduction (SCR) for NO_x control is included (refer to Section 3.0 for further details). Each HRSG will discharge to a metal exhaust stack approximately 160 feet tall. A stack damper will be included to minimize heat loss during unit shutdowns.

2.2.3 Steam Turbine Generator

The STG is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one high-pressure section with a nominal 1,822 pounds per square inch gauge (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 that will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system are included.

2.2.4 *Linear Mechanical Draft Cooling Tower*

The Project will utilize a multiple cell, mechanical draft, counterflow cooling tower for plant cooling. The cooling tower will be of fiberglass fill 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. A 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 potable water as an emergency source 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.

The basic principle behind all cooling towers is to cool water using ambient air. Circulating cooling water will remove heat from the steam, causing it to condense. The heated circulating cooling water is transported to the cooling tower to dissipate the heat into the atmosphere. The circulating water is sprayed into the cooling tower as a coarse mist that cascades down a fill material. As the circulating water falls, air contacts the water, allowing a transfer of heat from the water to the cooler atmospheric air. The draft, which causes the atmospheric air to pass through the cascading water, is created mechanically with fans. The cooled circulating water is then collected in the cooling tower basin, where it is pumped from the cooling tower back to the condenser water boxes, repeating the process.

During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust. To minimize this effect, the tower will be equipped with drift eliminators to provide multiple directional changes of airflow while preventing the escape of water droplets.

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. For the purpose of this project, it is assumed that 100 percent of the drift droplets are small enough so that all the drift generated will be dispersed and lose water due to evaporation, resulting in emissions of particulate matter. PM/PM_{10} emissions calculations for the LMDCT are presented in Appendix C.

2.2.5 Mode of Operation

Table 2-1 summarizes the emission units and corresponding operating limits proposed in this application.

Two operating scenarios are proposed in this application that correspond to the availability of natural gas fuel onsite. Under the first operating scenario (Scenario 1 - Pre-Onsite Natural Gas Availability), it is assumed that natural gas is not available onsite, and the Project will burn ULSFO exclusively. The second operating scenario (Scenario 2 - Post-Onsite Natural Gas Availability) is based on the availability of natural gas onsite, and the combustion of ULSFO as a back-up fuel. When natural gas becomes available on site, Scenario 1 will discontinue, and the Project will continue to operate under the conditions of Scenario 2. The following describes the proposed fuel and operating limits associated the aforementioned scenarios:

- **Scenario 1 (Pre-Onsite Natural Gas Availability):** Prior to the completion of the natural gas pipeline to the site, the Project (i.e., combined cycle operations) will have no access to natural gas for combustion as the primary fuel, and will be limited to the use of ULSFO. Under this scenario, JEA proposes to fire ULSFO for not more than 500 hours per year per CTG. Scenario 1 applies until such time as the natural gas pipeline construction is complete and commercial operation on natural gas is successfully achieved for the CTGs. Under this scenario, when the CTGs operate in a simple cycle mode with a by-pass stack, they will operate as outlined in Section 2.2.6 of the Application Support Document for the Simple Cycle Project (DEP File No. 0310561-001-AC (PSD-FL-401)).
- **Scenario 2 (Post-Onsite Natural Gas Availability)**: When the natural gas pipeline construction is complete and natural gas fuel is available onsite and commercial operation on natural gas has been successfully achieved on each CTG/HRSG, JEA proposes to fire each CTG/HRSG for 8,760 hours per year, with up to 500 hours per year per CTG on ULSFO, as a back-up. Under this scenario, when the CTGs operate in a simple cycle mode with a by-pass stack, they will operate as outlined in Section 2.2.6 of the Application Support Document for the Simple Cycle Project (DEP File No. 0310561-001-AC (PSD-FL-401))

Both operating scenarios described above are fully addressed in this application, including the air quality impact analyses and BACT determination. As shown in Section 4.0, the air quality analysis addresses a matrix of possible annual operating modes that include each CTG operating both as a simple cycle unit (with a by-pass stack) and with the HRSG as a combined cycle unit, exhausting through the HRSG stack. Additionally,

as further explained in Section 5.0 of this document, each CTG, while operating in a simple cycle mode will continue to be restricted to 17 hours of operation of maximum ULSFO use per calendar day (if ULSFO is fired exclusively) for compliance with regional haze impact thresholds. This translates to a requested daily ULSFO usage limit of 277 kgal/day per CTG. The combined cycle mode of operations will not result in any daily ULSFO limitations.

Table 2-1
Summary of Sources to be Permitted

Emission Units	Heat Input per Unit (MBtu/h)	Operational Limits
Each of the two CTG/HRSGs[a]	1,948 (natural gas, 7 °F) 1,778 (natural gas, ISO) Duct Burner: 189 MBtu/h	Pre-Onsite Natural Gas Availability: 500 hours per year Post-Onsite Natural Gas Availability: 8,760 hours per CTG/HRSG per year, with up to 500 hours per year on ULSFO as a back-up.
	2,101 (ULSFO, 7 °F) 1,948 (ULSFO, ISO) Duct Burner: 189 MBtu/h	

[a]Heat input for each CTG/HRSG based on higher heating value (HHV) at 100 percent load. Data based on GE performance guarantee.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of regulated and criteria air pollutants resulting from the GEC. Emissions from the GEC will be generated from the two General Electric 7FA CTGs, natural gas fired duct burners in the HRSGs, the LMDCT and other ancillary equipment previously considered as part of the simple cycle project. Performance data for each CTG/HRSG at 100 percent load with natural gas or ULSFO firing at ISO conditions were used to determine the PTE.

Ambient temperature data were selected based on meteorological data from Duval County, Florida. An ambient temperature of 7° F represents the seasonal minimum site temperature and corresponds to maximum heat input and power generation. An ambient temperature of 68.8° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 105° F represents the seasonal maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. A temperature of 59° F represents ISO conditions.

2.3.1 Units 1 and 2 CTG/HRSGs

The maximum and potential (at ISO conditions) pound per hour emission rates are presented in Table 2-2. Appendix B provides the performance data for each CTG/HRSG.

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

Pollutant	Natural Gas Firing (lb/h)		ULSFO Firing (lb/h)	
	Maximum[a]	At 59°F (ISO)[b]	Maximum[a]	At 59°F (ISO)[b]
NO_x[c]	15.4	14.2	71.5	66.7
SO_2[d]	8.7	8.0	3.2	3.0
CO[e]	35.5	32.7	55.5	40.6
PM/PM_{10} (front and back half)	29.7	29.1	40.8	40.7
VOC	3.9	3.6	6.1	5.8
Sulfuric Acid Mist (SAM)	5.33	4.9	1.7	1.6

[a]Maximum pound per hour emission rates for each CTG/HRSG considering all operating loads and ambient temperatures.
[b] Emission rates at ISO Conditions are for the 100 percent load case only and includes duct firing.
[c]NO_x emissions at ISO conditions are based on a SCR controlled NO_x emission rate of 2.0 ppmvd at 15 percent O_2 when firing natural gas and 8.0 ppmvd at 15 percent O_2 when firing ULSFO.
[d]Based on a natural gas sulfur content of 2 grains/100 scf and the use of ULSFO with 0.0015 percent sulfur content.
[e]CO emissions at ISO conditions are based on a CO emission rate of 7.6 ppmvd at 15 percent O_2 when firing natural gas and 8.0 ppmvd @ 15 percent O_2 when firing ULSFO.

2.4 GEC Potential to Emit

The annual PTE for GEC was estimated based on the hourly emission rate for each pollutant at ISO conditions, considering operation at 100 percent load, as well as the emissions from the other ancillary emission units. The annual PTE was then calculated for each of the two operational modes presented in Sections 2.2.5 and a matrix of possible annual operational scenarios that include simple cycle and combined cycle operations. Table 2-3 summarizes the facility PTE and points out the operational scenario that results in the highest annual PTE for each pollutant, respectively. Appendix C provides the detailed emission calculations.

Table 2-3
Post Combined Cycle-Conversion Worst Case PTE (tpy)

Emission Units	CO	NO_x	PM/PM_{10}	SO_2	VOC	H_2SO_4
Simple Cycle Operational Mode PTE[1]						
Units 1 and 2 SCCTs	67.70	340.20	71.00	28.81	10.85	11.03
Emergency Diesel Engine Generator	0.45	3.33	0.02	0.00	0.08	0.00
Emergency Diesel Fire Pump	0.07	0.57	0.03	0.00	0.08	0.00
Fuel Gas Heater	2.01	2.41	0.19	0.02	1.27	0.02
2 ULSFO Tanks					0.71	
TOTAL (SCCT Operations)	**70.24**	**346.51**	**71.25**	**28.82**	**13.00**	**11.05**
Combined Cycle Operational Mode PTE[2]						
Units 1 and 2 CCCTs	290.40	150.64	260.72	70.17	32.64	42.75
Emergency Diesel Engine Generator	0.45	3.33	0.02	0.00	0.08	0.00
Emergency Diesel Fire Pump	0.07	0.57	0.03	0.00	0.08	0.00
Fuel Gas Heater	2.01	2.41	0.19	0.02	1.27	0.02
Cooling Tower			4.26			
2 ULSFO Tanks					0.50	
TOTAL (CCCT Operations)	**292.95**	**156.95**	**265.22**	**70.19**	**34.57**	**42.78**
Worst Case Project PTE[3]	**292.95**	**447.45**	**265.22**	**70.96**	**34.57**	**42.78**
PSD SER	100	40	25/15	40	40	7
PSD Review Required Based on CCCT Emissions?	YES	YES	YES	YES	NO	YES

Notes [ ]:

[1] PTE (SCCT operational Mode) is the expected emissions from combustion turbine operation at 3,500 hours per CTG per year on natural gas alone or the combination of natural gas/ULSFO (3,000 hours per CTG per year on natural gas and 500 hours per CTG per year on ULSFO); whichever is greater. This operational scenario occurs post-construction of the natural gas pipeline and results in a PTE greater than the PTE from firing ULSFO 1,000 hours per year per CTG prior to the natural gas pipeline construction. Also included are potential emissions from the emergency ancillary equipment and the ULSFO storage tanks.

[2] PTE (CCCT operational mode) is the higher of the expected emissions from combustion turbine/duct burner operation at 8,760 hours per CTG/HRSG per year on natural gas alone, OR, the combination of natural gas/ULSFO (8,260 hours per CTG/HRSG per year on natural gas and 500 hours per CTG per year on ULSFO and duct burners on gas). Also included are the emissions from the emergency ancillary equipment (no change from the SCCT operational mode), the ULSFO storage tanks and the cooling tower.

[3] Worst Case Project PTE for emissions of CO, PM/PM_{10} and VOCs occur when each CCCT operates 8,260 hours/year on natural gas and 500 hours/year on ULSFO. Worst Case Project PTE for emissions of SO_2 occurs when each SCCT operates 3500 hours per year on natural gas and each CCCT operates 5,260 hours per year on natural gas. Worst Case Project PTE for emissions of H_2SO_4 occurs when each CCCT operates 8,760 hours/year on natural gas. Worst Case Project PTE for emissions of NO_x occur when each SCCT operates 3,000 hours/year on natural gas and 500 hours/year on ULSFO, and each CCCT operates 4,760 hours per year on natural gas and 500 hours/year on ULSFO, respectively. Project PTE includes emissions from emergency ancillary equipment. The emergency ancillary equipment will retain the same operational limits as proposed in the SCCT air permit application package (refer to DEP File No. 0310561-001-AC- (PSD-FL-401))

4760 Gas + 500 oil = 5260

3000 Fg + 500 duct = 3500

8260 + 500 = 8760

5260 + 3500 = 8760

2.4.1 Hazardous Air Pollutant Emissions

The GEC will not be a major source of hazardous air pollutants. Refer to Appendix C for hazardous air pollutant emission calculations.

2.5 Federal and State Air Quality Requirements

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

2.5.1 Rule Applicability to the Facility

This section provides a review of the New Source Review (NSR) applicability for the facility.

2.5.1.1 New Source Review. The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications at existing major sources under two programs; the PSD program outlined in 40 CFR 52.21 for areas in attainment, and the NSR program outlined in 40 CFR 51 and 52 for areas considered nonattainment for certain pollutants.

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable Ambient Air Quality Standards (AAQS). Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the AAQS. A review of the air quality attainment status of Duval County reveals that the proposed Project is located in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program will apply to the proposed Project, as administered by the state of Florida under 62-212.400, F.A.C., *Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.*

2.5.1.2 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 AAQS while providing a margin for future industrial and commercial growth. The primary provisions of the PSD regulations require that major modifications and new major stationary sources be reviewed prior to construction to ensure compliance with the AAQS, the applicable PSD air quality increments, and the requirements to apply BACT.

A major stationary source is defined as any one of the listed major source categories that emits, or has the PTE, 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories.

The proposed Project qualifies as one of the 28 major source named categories (i.e., fossil fuel fired steam electric plant) and as shown in Table 2-3, has a PTE greater than 100 tpy for at least one regulated pollutant. The estimated PTE of NO_x, CO, PM/PM_{10}, and H_2SO_4 exceed the PSD significant emission rates of 40, 100, 25/15, and 7 tpy, respectively. Therefore, the preceding pollutants are subject to PSD review. The PSD review includes a BACT analysis, an AQIA, and an assessment of the GEC's total impact on general residential and commercial growth, soils and vegetation, and visibility, as well as a Class I area impact analysis. These analyses are included in Sections 3.0, 4.0, and 5.0, respectively.

2.5.2 Rule Applicability to Units 1 and 2 Combined Cycle Units

The following sections include a discussion of the applicability of regulations to the Units 1 and 2 CCCTs.

2.5.2.1 New Source Performance Standards. The New Source Performance Standards (NSPS) established in the 1970 CAA, were developed for specific industrial categories and are promulgated in 40 CFR 60 and adopted by reference in Rule 62-204.800(8)(b)39, F.A.C.

Both of the CTGs/HRSGs are subject to *Standards of Performance for Stationary Combustion Turbines*. The NSPS are found at 40 CFR Part 60 Subpart KKKK and are adopted by reference in Rule 62-204.800(8)(b)77, F.A.C. Subpart KKKK includes standards for regulation of NO_x and SO_2 as follows:

- NO_x--15 ppm (parts per million) at 15 percent O_2 or 54 ng/J (nanogram per joule) of useful output (0.43 lb/MWh) – new turbines firing natural gas with > 850 MBtu/h heat input.
- NO_x--42 ppm (parts per million) at 15 percent O_2 or 160 ng/J (nanogram per joule) of useful output (1.3 lb/MWh) – new turbines firing fuel oil with > 850 MBtu/h heat input.
- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

The criteria for this NSPS will be met or exceeded by the proposed project.

2.5.2.2 National Emission Standards for Hazardous Air Pollutants. On March 5, 2004, the United States Environmental Protection Agency (USEPA) 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 annual HAP emissions from the GEC (post-combined cycle conversion) are based on the AP-42 HAP emission factors. It should be noted that the formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5; http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100 percent load and lean pre-mix technology. The Access Database emission factor for formaldehyde is more representative than the emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.

As shown in the HAP emission tables in Appendix C, no individual HAP has a PTE in excess of 10 tpy and no combination of HAPs has a PTE in excess of 25 tpy from the GEC. Because, the potential emissions of all HAPs, both individually and combined, are less than the HAP major source threshold levels of 10 tpy for individual HAPs and 25 tpy for combined HAPs (10/25 tpy), the GEC is a minor source for HAP emissions and therefore not subject to the CT MACT.

There is no applicable MACT standard for the cooling tower because chromium-based chemicals are will not be used by JEA in the proposed cooling tower.

2.5.3 Excess Emissions

As with other combustion turbines of this size and type, excess emissions during startup, shutdown, malfunction, DLN tuning, and fuel switching are likely to occur and are accounted for in FDEP permitting of combustion turbines. In accordance with Rule 62-210.700, F.A.C., JEA is requesting that the permit allow for 2 hours of excess emissions in any 24 hour period due to startup, shutdown, malfunction or fuel switching (a fuel switch is considered a form of startup). It is also recognized that excess emissions may occur during major DLN tuning. JEA is requesting that the permit include the following condition in regards to allowing for excess emissions during DLN tuning sessions.

> *"DLN tuning: CEMS data collected during initial or other major DLN tuning sessions may be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications or determined best practices. 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 of at least one (1) day that details the activity and proposed tuning schedule, provided excess emissions are anticipated. The notice may be by telephone, facsimile transmittal, or electronic mail."

3.0 Best Available Control Technology

A detailed BACT analysis for the Project has been included as Appendix D. A summary of the BACT analysis for the proposed Project is provided below:

- Nitrogen oxides (NO_x) emissions-- BACT was determined to be the use of SCR and dry low-NO_x (DLN) burners and good combustion controls to achieve 2.0 ppmvd at 15 percent O_2 while firing natural gas. BACT was determined to be the use of SCR, DLN burners and water injection to achieve 8.0 ppmvd at 15 percent O_2 while firing ULSFO.
- Carbon monoxide (CO) emissions-- BACT was determined to be the use of good combustion controls to achieve 7.6 ppmvd at 15 percent O_2 when firing natural gas and 8.0 ppmvd @ 15 percent O_2 when firing ULSFO.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and firing natural gas or ULSFO.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of natural gas and ULSFO.
- Sulfuric acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls while firing natural gas and ULSFO.

4.0 Class II Ambient Air Quality Analysis

The following sections discuss the air dispersion modeling methodology and the modeling results from the AAQIA for the proposed Project. This AAQIA has been performed for those emitted criteria pollutants subject to PSD review (PSD applicability based on the combined cycle operation) for which an AAQS exists (i.e., NO_x, PM_{10}, SO_2, and CO). The AAQIA was conducted in accordance with USEPA Guideline on Air Quality Models (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 JEA. The FDEP provided verbal approval of the proposed modeling methodologies with minor comments, discussed in later sections, during the project kickoff meeting on July 15, 2008. A copy of the protocol is presented in Appendix E.

4.1 Class II Model Selection

Consistent with the Appendix W *Guideline on Air Quality Models*, the American Meteorological Society/Environmental Protection Agency (AMS/EPA) Regulatory Model (AERMOD, Version 07026) air dispersion model was used to predict maximum ground-level concentrations associated with the proposed Project's emissions. The AERMOD model was established as the EPA preferred air dispersion model effective December 9, 2005, for regulatory applications[1]. AERMOD is the product of AMS/EPA Regulatory Model Improvement Committee (AERMIC), formed to introduce state-of-the-art modeling concepts into USEPA's air quality models. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. The AERMOD model includes a wide range of options for modeling air quality impacts of pollution sources.

4.2 Model Inputs and Options

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

4.2.1 Model Input Source Parameters

The AERMOD model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from

[1] Federal Register, Volume 70, No. 216. November 9, 2005. EPA 40 CFR Part 51, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions. Final Rule

various operating loads, operating scenarios, and ambient temperatures. Performance data for the combined cycle combustion turbines operating at several different loads (50, 75, and 100 percent) over a range of ambient temperatures (7, 59, 68.8, and 105° 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 Tables Table 4-1 and Table 4-2. For all load cases, the parameters in Tables Table 4-1 and Table 4-2 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 emergency diesel fire pump, emergency diesel engine generator, and the natural gas heater were also included in the modeling. Manufacturer's specification sheets and the emission calculations for these emission units were included in the Simple Cycle Operation Application submitted in May 2008. As noted in the May 2008 submittal, emissions from the emergency diesel fire pump and emergency diesel engine generator in the AAQIA were based on each unit operating 24 hours per day, and 400 and 230 hours per year, respectively.

As discussed in Section 2, the facility will have the capability to operate the turbines in either simple cycle mode or combined cycle mode which will result in multiple combinations of operating modes. The modeling analyses performed were characterized into worst-case scenarios, thus insuring the facility's operation meet the applicable air quality standards. Scenarios 1 and 2 in Section 2 above are represented by Scenarios 1 and 2, respectively, in Table 4-1. The remaining five scenarios presented in Table 4-1 represents the worst-case, mixed mode operating scenarios.

4.2.2 Dispersion Coefficient

With the introduction of AERMOD, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of assigning specific sources to have an urban effect, thus enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area.

Section 7.2.3 of the *Guideline on Air Quality Models* (incorporated as Appendix W of 40 CFR 51) provides the basis for determining the urban/rural status of a source. It was determined that the land use procedure described in Section 7.2.3(c) was sufficient for determining the urban/rural status. The land use procedure is as follows:

- Classify the land use within the total area, A_o, circumscribed by a 3 km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multi-family compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on a visual inspection of the USGS 7.5-minute topographic map of the proposed site location, it was concluded that over 50 percent of the area surrounding the proposed Project is rural. Since the proposed Project is not located in an urbanized area, urban boundary layer option was not invoked.

Table 4-1
Stack Parameters and Pollutant Emission Rates Used in Annual AERMOD Modeling Analyses

Scenario	Source	Mode	Load	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}[d]	CO
1	Unit 1	SCCT[a]	100	115.00	20.00	123.00	1040.00	40.61	0.30	3.88	4.70
		CCCT[a]	100	160.00	18.00	73.65	321.00	4.08	0.18	2.33	2.49
	Unit 2	SCCT[a]	100	115.00	20.00	123.00	1040.00	40.61	0.30	3.88	4.70
		CCCT[a]	100	160.00	18.00	73.65	321.00	4.08	0.18	2.33	2.49
2	Unit 1	SCCT[a]	100	115.00	20.00	N/A	N/A	N/A	N/A	N/A	N/A
		CCCT[a]	100	160.00	18.00	59.10	190.00	15.40	8.68	29.70	35.50
	Unit 2	SCCT[a]	100	115.00	20.00	N/A	N/A	N/A	N/A	N/A	N/A
		CCCT[a]	100	160.00	18.00	59.10	190.00	15.40	8.68	29.70	35.50
3	Unit 1	SCCT[a]	100	115.00	20.00	N/A	N/A	N/A	N/A	N/A	N/A
		CCCT[a]	100	160.00	18.00	59.10	190.00	18.60	8.37	30.33	35.96
	Unit 2	SCCT[a]	100	115.00	20.00	N/A	N/A	N/A	N/A	N/A	N/A
		CCCT[a]	100	160.00	18.00	59.10	190.00	18.60	8.37	30.33	35.96
4	Unit 1	SCCT[a]	100	115.00	20.00	118.00	1060.00	25.57	3.60	7.19	7.11
		CCCT[a]	100	160.00	18.00	59.10	190.00	12.45	4.90	18.47	21.78
	Unit 2	SCCT[a]	100	115.00	20.00	118.00	1060.00	25.57	3.60	7.19	7.11
		CCCT[a]	100	160.00	18.00	59.10	190.00	12.45	4.90	18.47	21.78
5	Unit 1	SCCT[a]	100	115.00	20.00	118.00	1040.00	42.22	3.24	8.11	8.45
		CCCT[a]	100	160.00	18.00	59.10	190.00	9.25	5.21	17.83	21.32
	Unit 2	SCCT[a]	100	115.00	20.00	118.00	1040.00	42.22	3.24	8.11	8.45
		CCCT[a]	100	160.00	18.00	59.10	190.00	9.25	5.21	17.83	21.32
6	Unit 1	SCCT[a]	100	115.00	20.00	118.00	1060.00	25.57	3.60	7.19	7.11
		CCCT[a]	100	160.00	18.00	59.10	190.00	9.25	5.21	17.83	21.32
	Unit 2	SCCT[a]	100	115.00	20.00	118.00	1060.00	25.57	3.60	7.19	7.11
		CCCT[a]	100	160.00	18.00	59.10	190.00	9.25	5.21	17.83	21.32

Table 4-1 (cont.)
Stack Parameters and Pollutant Emission Rates
Used in Annual AERMOD Modeling Analyses

Scenario	Source	Mode	Load	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}[d]	CO
7	Unit 1	SCCT[a]	100	115.00	20.00	118.00	1040.00	42.22	3.24	8.11	8.45
		CCCT[a]	100	160.00	18.00	59.10	190.00	12.45	4.90	18.47	21.78
	Unit 2	SCCT[a]	100	115.00	20.00	118.00	1040.00	42.22	3.24	8.11	8.45
		CCCT[a]	100	160.00	18.00	59.10	190.00	12.45	4.90	18.47	21.78
All	Fire Pump[b]	NA	100	15.17	0.42	286.63	806.00	1.29E-01	1.64E-04	7.40E-03	N/A
	Generator[b]	NA	100	24.00	0.67	528.60	762.80	7.61E-01	5.83E-04	5.25E-03	N/A
	Heater[c]	NA	100	20.00	2.00	7.29	1,165.00	5.50E-01	3.43E-03	4.35E-02	N/A

[a]Emissions for the CTGs are per stack. For the annual modeling scenario, annualized emissions are based on the scenarios outlined in Section 2 above. When annual emissions are derived from a combination of operation on natural gas and ULSFO, the lowest exit temperature and exit velocity of the two fuels is conservatively assumed.
[b]Emissions from these units are based on operation for testing purposes firing ULSFO. As such the emissions for the annual averaging periods are based on 400 hours per year of operation for the fire pump and 230 hours per year for the emergency diesel engine generator.
[c]Emissions for the natural gas fuel heater are based on 8,760 hours per year of operation.
[d]PM/PM_{10} emission rates represent both front and back half emissions.

Table 4-2
Stack Parameters and Pollutant Emission Rates Used in Short-term AERMOD Modeling Analyses

Scenario	Source	Mode	Load	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}[d]	CO
Natural Gas	Units 1 or 2	CCCT[a]	100	160.00	18.00	59.10	190.00	N/A	8.68	29.70	35.50
			75	160.00	18.00	49.72	191.00	N/A	6.98	22.20	25.40
			50	160.00	18.00	41.51	183.00	N/A	5.54	21.30	21.00
	Units 1 or 2	SCCT[a, e]	100	115.00	20.00	118.00	1,060.00	N/A	9.01	18.00	17.80
			75	115.00	20.00	102.00	1,118.00	N/A	7.27	18.00	25.30
			50	115.00	20.00	86.00	1,169.00	N/A	5.77	18.00	21.00
	Heater[c]	NA	100	20.00	2.00	7.29	1,165.00	N/A	3.43E-03	4.35E-02	4.60E-01
Fuel Oil	Units 1 or 2	CCCT[a]	100	160.00	18.00	73.65	321.00	N/A	3.19	40.80	43.60
			75	160.00	18.00	60.92	318.00	N/A	2.02	35.20	55.50
			50	160.00	18.00	50.97	315.00	N/A	1.58	34.90	45.10
	Units 1 or 2	SCCT[a, e]	100	115.00	20.00	123.00	1,040.00	N/A	2.65	34.00	41.20
			75	115.00	20.00	105.00	1,120.00	N/A	2.12	34.00	55.10
			50	115.00	20.00	88.00	1,170.00	N/A	1.66	34.00	45.00
	Fire Pump[b]	NA	100	15.17	0.42	286.63	806.00	N/A	3.59E-03	1.62E-01	3.70E-01
	Generator[b]	NA	100	24.00	0.67	528.60	762.80	N/A	2.22E-02	2.00E-01	3.95E+00

[a]Emissions for the CTGs are per stack. For the short-term modeling scenario, emissions from operation on natural gas and operation on ULSFO were modeled separately since each fuel can be fired for 24-hours per day. CTG emissions given by load are enveloped over several ambient temperatures and modes of operation to produce worst case operation by load.
[b]Emissions from these units are based on operation for testing purposes firing ULSFO. As such the emissions for the short-term averaging periods are based on 24-hours per day of operation.
[c]Emissions for the natural gas fuel heater are based on 24-hours per day for short-term operation.
[d]PM/PM_{10} emission rates represent both front and back half emissions.
[e]SCCT stack parameter values are the same as those presented in the simple cycle application dated April 2008.

4.2.3 Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. GEP stack height is defined as the greater of:

1. 65 meters,
2. a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where:

Hg = GEP stack height
H = height of nearby structure(s)
L = lesser dimension (height or projected width) of nearby structure(s)

3. a height demonstrated by a fluid model or a field study which ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

Since a fluid model analysis or a field study will not be completed, the GEP stack height is defined by definition 1 or 2. Subsequently, the term *nearby* is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters.

For these analyses, the buildings and structures of the proposed combined cycle facility were analyzed to determine the potential to influence the plume dispersion from the combustion turbines and ancillary sources' stacks. Structure dimensions and relative locations were entered into the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program Prime (BPIPPRM, Version 04274) to produce an AERMOD input file with direction specific building downwash parameters. The BPIPPRM formula GEP heights for the HRSG stacks are 72.41 m (237.57 ft) for the north stack and 72.56 m (238.06 ft) for the south stack. The proposed HRSG stack heights are each 48.768 m (160 ft). As such, direction-specific downwash parameters from the BPIPPRM program were included in the AERMOD air dispersion modeling analysis.

4.2.4 Model Default Options

Since the AERMOD model is especially designed to support the USEPA's regulatory modeling programs, the regulatory modeling options are considered the default mode of operation for the model. These options include the use of stack-tip downwash and a routine for processing averages when calm winds or missing meteorological data occur.

4.2.5 AERMOD 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 out 10 km from the center of the proposed location was used. The nested rectangular grid network consists of four tiers: the first tier extends from the center of the site to 1 km with 100 m spacing; the second tier extends from 1 km to 2.5 km with 250 m spacing; the third tier extends from 2.5 km to 5 km with 500 m spacing; and the fourth tier extends from 5 km to 10 km with 1,000 m spacing. Receptors were placed at 50 m intervals along the property's security boundary (i.e., that area to which public access is physically restricted).

Terrain elevations at receptors were obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files and incorporated into the AERMOD model. There is no distinction in AERMOD between elevated terrain below release height and terrain above release height, as with earlier regulatory models that distinguished between simple terrain and complex terrain. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10 percent elevation slope from any given receptor. A visual inspection of the surrounding DEM files was performed to ensure that all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations were determined using a method that locates interpolated terrain elevation near each receptor. This method ensures that the most representative elevation of the surrounding nearby terrain points in the DEM files are used for each receptor.

4.2.6 Meteorological Data

The AERMOD model utilizes a file of surface boundary layer parameters and a file of profile variables including wind speed, wind direction, and turbulence parameters. These two types of meteorological inputs are generated by the meteorological preprocessor for AERMOD, which is called AERMET (Version 06341). AERMET includes three stages of preprocessing of the meteorological data. The first two stages extract, quality check, and merge the available meteorological data. The third stage requires input of certain surface characteristics (surface roughness, Bowen ratio, and albedo) from the area of concern.

AERMET requires hourly input of specific surface and upper air meteorological data. These data, at a minimum, include the wind flow vector, wind speed, ambient temperature, cloud cover, and morning radiosonde observation, including height, pressure, and temperature. Surface characteristics in the vicinity of the proposed emissions sources are important in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface affect the calculations of the boundary layer parameters and are quantified by the following variables: surface roughness length, surface Albedo, and Bowen ratio, respectively.

Representative Hourly Meteorological Data

The *Appendix W – Guideline on Air Quality Models* (November 2005), the *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005, Feb 2000), and the *Draft New Source Review Workshop Manual* (October 1990) indicate that when site-specific data are not available, 5 years of *adequately representative* data from a nearby National Weather Service station may be used. The analyses presented herein utilize 5 years (2001-2005) of meteorological data from the Jacksonville International Airport (JAX) as data representative of the Project location.

Representativeness of meteorological data is dependent on the following four factors:

- Spatial--The proximity of the meteorological monitoring site to the area under consideration.
- Temporal--The period of time during which the data is collected.
- Exposure--The siting of the meteorological instruments at the monitoring site.
- Geographic--The geographic features and land use cover in the vicinity of the monitoring site.

Spatial

The spatial representativeness of the meteorological data can be adversely affected by large distances between the source and the monitoring site. As, such, spatial representativeness is best achieved by using meteorological data in close proximity to the area under consideration. JAX is certainly in close proximity to the facility being located only 26 miles north-northwest. Additionally, the elevation of JAX (32 ft) is similar to that of the facility location (30 ft).

Temporal

Temporal representativeness of the meteorological data refers to year-to-year variations or climatological accuracy of the data. The period or record of meteorological data should be sufficient to ensure that the worst-case meteorological dispersion conditions are adequately captured and provide a stable distribution of meteorological conditions. Too short of record may cause excessive variability in the model predicted concentrations.

The *Guideline on Air Quality Models* concludes that the variability of model estimates is adequately reduced if a 5-year period of record of meteorological data is used. The *Draft New Source Review Workshop Manual* indicates that the "5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations." By using 5 years of meteorological data, the model contains 35,040 more hourly observations with which to predict concentrations than a single year of site-specific observations.

JAX has numerous years of data available for use in air dispersion modeling. The simulations presented here use the 5-year data set from 2001 through 2005 as received by the FDEP for use in air dispersion modeling demonstrations.

Exposure

As given in the document *Meteorological Data Representivity Analysis* (http://www.iowadnr.gov/air/prof/tech/files/representivity_analysis.pdf), produced by the Iowa Department of Natural Resources:

> *Instrument exposure refers to the ability of the instruments to measure meteorological conditions without the influence of manmade or natural obstructions. If obstructions are present, they can influence the measurements of the meteorological monitoring site.*

The meteorological data observations at JAX are derived from an Automated Surface Observing Station (ASOS), which are located at all major airports. The *Federal Standard for Siting Meteorological Sensors at Airports* requires that sensors be installed in appropriate locations to assure that the resultant observations are representative of the

meteorological conditions. Because of this, it is determined that instrument exposure does not affect the representativeness of JAX meteorological data.

Geographic

Geographic representativeness refers to the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site and can thus influence atmospheric dispersion. The effects of geographic features and land cover on representativeness require a degree of professional judgment. There are no significant geographic terrain features in the area that would greatly influence the wind flow in the area. Additionally, JAX and the facility location are each located in close proximity to the Atlantic Ocean, 16 miles and 9 miles, respectively.

As mentioned previously, geographic representativeness also includes the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site. AERMOD uses three landuse-based surface characteristics in its dispersion algorithms: 1) surface roughness (z_o), 2) Bowen ratio (B_o), and 3) albedo (r). The USEPA's *AERMOD Implementation Guide* (updated January 2008) provides a indication of how one may determine representativeness.

> *When using National Weather Service (NWS) data for AERMOD, data representativeness can be thought of in terms of constructing realistic planetary boundary layer (PBL) similarity profiles. As such, the determination of representativeness should include a comparison of the surface characteristics (i.e., z_o, B_o and r) between the NWS measurement site and the source location, coupled with a determination of the importance of those differences relative to predicted concentrations.*

The recently released AERSURFACE tool (Version 08009), was used to process land cover data to determine the annual surface characteristics for both the facility location and JAX. The results of the AERSURFACE simulation are presented in Table 4-3.

Sensitivity runs performed by the USEPA and presented at the 8th Modeling Conference (held September 2005 at Research Triangle Park) demonstrate that resulting model-predicted concentrations from buoyant and very buoyant stacks between 35 and 50 meters in height (similar to the stacks proposed herein) remain nearly flat as the three surface characteristics are altered within their potential range of values. Given the results of the USEPA sensitivity analysis and the fact the resulting values of the three site characteristics lie in close proximity to one another given the range of potential values, the values presented here are in good agreement with one another as to deem JAX representative from a landuse standpoint.

Table 4-3
Annual Surface Characteristics

Location	Albedo	Bowen Ratio	Surface Roughness
Facility	0.14	0.41	0.61
JAX	0.14	0.48	0.32

Notes:
Potential values range as follows:
Albedo: 0.1 – 0.6.
Bowen ratio: 0.1 – 6.0.
Surface roughness: 0.0001 – 1.3.

Conclusion

The above demonstration, including the four factor test and a comparison of landuse surface characteristics concludes that the use of existing adequately representative meteorological data from JAX in the AERMOD model is protective of air quality standards (including PSD Increment) and thereby acceptable for use in the AAQIA.

AERMET Processing

At the pre-application meeting on July 15, 2008, FDEP stated that the meteorological data provided for the simple cycle application submitted in April 2008 did not incorporate the revisions EPA recently made to the guidelines on determining the surface characteristics for use in the AERMET pre-processor[2]. Specifically, the changes to these determinations pertain to the domain in which the individual surface characteristics are determined and the computational method for processing the data. As such, FDEP requested that Stage 3 of AERMET be reran using the new guidance information.

The effective surface roughness length should be based on an upwind distance that captures the net influence of surface roughness elements on the measured wind speeds needed to properly characterize the magnitude of mechanical turbulence in the approach flow. As such, the recommended upwind distance for processing land cover data to determine the surface roughness parameter is one kilometer relative to the meteorological tower location. Additionally, it is recommended to use an inverse-distance weighted geometric mean for computing the surface roughness from the land cover data.

[2] USEPA. "AERMOD Implementation Guide". Office of Air Quality Planning and Standards, Air Quality Assessment Division. Research Triangle Park, North Carolina. January 9, 2008.

The estimates of convective turbulence are not as directly linked with tower measurement location as the linkage between the measured wind speed and the estimation of mechanical turbulence (i.e., surface roughness elements). As such, the recommended approach to determine the effective Bowen ratio and albedo values is to average the surface characteristics across a 10-km by 10-km region centered on the measurement site. However, for cases in which the majority of sources are elevated releases, the domain may be more appropriately centered around the application site. Since all the sources for this Project are elevated sources, the domain for determining the Bowen ratio and albedo was centered around the application site. The Bowen ratio was computed using a geometric mean while the albedo was computed using an arithmetic average, as recommended by the EPA.

The calculations for the surface characteristic were accomplished by utilizing the recently release AERSURFACE (Version 00809) program. The 1-km radius domain for the surface roughness length was divided into three sectors: sector one starting at 43 degrees, sector two starting at 141 degrees, and sector three starting at 268 degrees. The Bowen ratio is dependant on the surface moisture condition and is categorized as either average, wet, or dry. The AERMOD Implementation Guide recommends basing this categorization on the 30-year climatological record and grouping the precipitation for the modeling year as wet if the rainfall amount is in the upper 30th percentile, dry if in the lower 30th percentile, and average for the remainder. This approach results in the meteorological years of 2001-2003 being categorized as average and the years 2004-2005 categorized as wet. The three surface characteristics (albedo, Bowen ratio, and surface roughness) are also dependent on the type of season. The AERSURFACE program has default settings for the month/season assignments; however, since Jacksonville does not have a typical seasonal pattern as characterized in these default settings, changes were made to these settings and are presented in Table 4-4. The electronic input and output files for AERSURFACE are included in the CD in Appendix F.

Table 4-4
AERSURFACE Seasonal Assignments

Season Description	Months
Late autumn after frost and harvest, or winter with no snow	12, 1, 2
Transitional spring (partial green coverage, short annuals)	3, 4
Midsummer with lush vegetation	5, 6, 7, 8, 9
Autumn with unharvested cropland	10, 11

4.3 Model Predicted Impacts

As presented in Section 2.0, the Project's potential future combined cycle PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, PM/PM_{10}, and CO. In accordance with the submitted modeling protocol, AERMOD air dispersion modeling was performed for these pollutants (as described in the preceding sections). Table 4-5 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 4-5 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 analyses (i.e., PSD increment and Ambient Air Quality Standards analyses) are required.

If any of the maximum impact concentrations or concentrations within 10 percent of the maximum impact source groups from each pollutant and averaging period, occurred at the edge of or beyond the 100 m fine grid, a 100 m refined receptor grid was placed around the impact to ensure that an absolute maximum concentration was obtained from the model.

Electronic copies of all Class II modeling input and output files are included in Attachment F.

Table 4-5
AERMOD Model-Predicted Class II Impacts

Pollutant	Fuel	Averaging Period	Mode of Operation	Model-Predicted Impact[a] ($\mu g/m^3$)			PSD Class II SIL[b] ($\mu g/m^3$)	Exceed SILs?	De Minimis Monitoring Level[c] ($\mu g/m^3$)	Pre-Construction Monitoring Required?
				100%	75%	50%				
NO_x	NG/ULSFO[d]	Annual	(f)	0.90	--	--	1	NO	14	NO
SO_2	NG/ULSFO[d]	Annual	(f)	0.09	--	--	1	NO	--	N/A
	NG	24 Hour	CCCT	0.91	0.90	0.88	5	NO	13	NO
			(g)	0.52	0.51	0.51		NO		NO
	ULSFO		CCCT	0.20	0.16	0.15		NO		NO
			(g)	0.14	0.14	0.14		NO		NO
	NG	3 Hour	CCCT	3.07	2.70	2.40	25	NO	--	N/A
			(g)	1.79	1.60	1.44		NO		N/A
	ULSFO		CCCT	0.73	0.57	0.51		NO		N/A
			(g)	0.45	0.37	0.37		NO		N/A
PM/PM_{10}[e]	NG/ULSFO[d]	Annual	(f)	0.34	--	--	1	NO	--	N/A
	NG	24 Hour	CCCT	3.97	3.98	4.03	5	NO	10	NO
			(g)	3.96	3.97	4.00		NO		NO
	ULSFO		CCCT	3.96	3.96	3.98		NO		NO
			(g)	3.96	3.96	3.98		NO		NO

Table 4-5 (cont.)
AERMOD Model-Predicted Class II Impacts

Pollutant	Fuel	Averaging Period	Mode of Operation	Model-Predicted Impact[a] (µg/m³)			PSD Class II SIL[b] (µg/m³)	Exceed SILs?	De Minimis Monitoring Level[c] (µg/m³)	Pre-Construction Monitoring Required?
				100%	75%	50%				
CO	NG	8 Hour	CCCT	47.75	47.75	47.75	500	NO	575	NO
			(g)	47.76	47.76	47.76		NO		NO
	ULSFO		CCCT	47.75	47.75	47.75		NO		NO
			(g)	47.76	47.77	47.76		NO		NO
	NG	1 Hour	CCCT	81.68	81.68	81.68	2,000	NO	--	N/A
			(g)	81.68	81.68	81.68		NO		N/A
	ULSFO		CCCT	81.68	81.68	81.68		NO		N/A
			(g)	81.69	81.70	81.69		NO		N/A

[a]Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data: 2001, 2002, 2003, 2004, and 2005 modeled at each corresponding load and include operation of the two CTGs, two HRSGs, emergency diesel engine generator, fire pump, and natural gas heater.
[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]Impacts are from one of the annual modeling scenarios outlined in Section 2.
[e]Note that the PM_{10} impacts are below the PM_{10} PSD Class II SILs and that the AAQS 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 (in accordance with the USEPA's guidance memorandum related to the interim implementation of NSR for PM 2.5), then the impacts would be significantly below the $PM_{2.5}$ AAQS.
(f)One of the scenarios outlined in Section 2.
(g)One unit in simple cycle mode and the other unit in combined cycle mode.

4.3.1 Pre-construction Monitoring

The maximum predicted concentrations presented in Table 4-5 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 for NO_x, CO, SO_2, and PM_{10}.

As given in rule 62-212.400(3)(e)1.e, F.A.C., no de minimis air quality level is provided for ozone. According to this rule, an ambient impact analysis and pre-construction ozone monitoring may be required for projects with emissions greater than 100 tpy of either NO_x or VOC. The PTE of VOC emissions are less than 100 tpy, but NO_x emissions are greater than 100 tpy (NO_x emissions will be significantly reduced once the facility is converted to combined cycle operation).

Ozone is a regional issue driven by the interaction of regional emissions sources of NO_x and VOC and those pollutants' reactivity in the presence of sunlight to form ground-level ozone. Ozone predictions are typically made with the use of resource intensive, multi-source, photochemical grid models performed at the research level for air quality planning purposes. Consequently, the use of photochemical models to assess individual point sources has been limited and is not common place.

However, Richard Scheffe developed "VOC/NO_x Point Source Screening Tables" (EPA-OAQPS-TSD-SRAB, 1988) to conservatively estimate ozone increases from individual sources on a short-term basis (based on prior regional reactive gas modeling). According to the documentation, his screening technique has been designed to be both robust and simple to use, while maintaining several inherent assumptions which lead to conservative ozone increment predictions. Scheffe created two separate ozone lookup tables: one for rural areas and one for urban areas. The urban table yields higher ozone estimates and as such was used in this analysis. The urban screening table provides ozone increments as a function of VOC mass emission rates and VOC/NO_x emissions ratios. The urban table estimates that the project could conservatively have a 0.0021 ppm (4.12 $\mu g/m^3$) ozone impact. While no significant impact level (SIL) exists for ozone, the Scheffe estimate is only 2.8 percent of the current 0.075 ppm 8-hour ozone AAQS and only 1.8 percent of the previous 0.12 ppm 1-hour ozone AAQS. The SILs for other short-term period PSD pollutants such as CO, SO_2, and PM_{10} average 3.4 percent of their respective AAQS. As presented immediately above, the Scheffe-estimated ozone impact for this project is below the average SIL-to-AAQS ratio of other short-term averaged PSD pollutants. Therefore, it is assumed that the project's contribution to ozone will be insignificant and the applicant requests an exemption from the PSD pre-construction monitoring requirement for ozone.

5.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for combined cycle operation at the GEC site, analyses of the proposed Project's effect on all Class I areas within 300 km were performed. Specifically, Bradwell Bay Wilderness (BBW), Chassahowitzka Wilderness (CW), Okefenokee Wilderness (OW), St. Marks Wilderness (SMW), and Wolf Island Wilderness (WIW) areas are the Class I areas of concern for this project. 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 SILs were evaluated and compared to the recommended thresholds. Figure 5-1 presents the location of the proposed Project site with respect to the Class I areas.

The methodology of the refined California Puff (CALPUFF) analysis followed 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, and an air dispersion modeling protocol sent to FDEP on July 15, 2008 (Appendix E). The following sections include discussions of the air modeling approach to assess impacts at each of the aforementioned Class I areas, as well as the resulting model-predicted impacts from the Project onto these areas.

5.1 Class I Model Selection and Inputs

5.1.1 Model Selection

The CALPUFF (Version 5.8, Level 070623) air modeling system was used to model the proposed Project and assess the AQRVs at each of the aforementioned Class I areas. 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 (Version 5.8, Level 070623), 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. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech to produce CALPUFF ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor. VISTAS has provided 2001-2003 CALMET files for five 4-km sub-regional domains as illustrated on Figure 5-2.

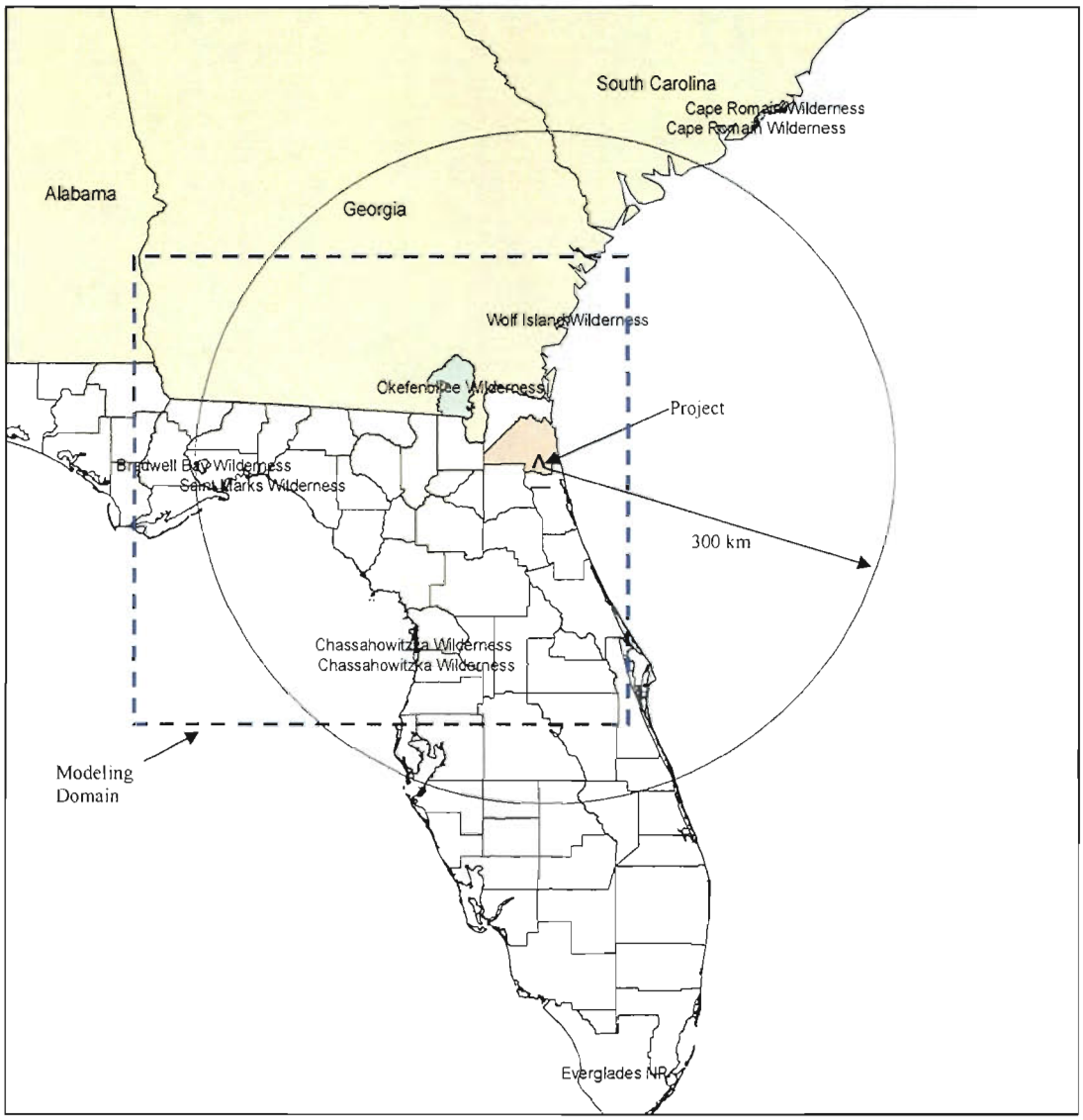

Figure 5-1
Proposed Project Location and Class I Areas

This modeling analysis used the CALMET files prepared for sub-domain 2.

5.1.2 CALPUFF Model Settings

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

5.1.3 Building Wake Effects

The CALPUFF analysis included the 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 USEPA's PRIME version of Building Profile Input Program (BPIPPRM, Version 04274) and included in the CALPUFF model input.

5.1.4 Receptor Locations

The CALPUFF analyses used an array of discrete receptors over the Class I areas, which were created and distributed by the NPS. Specifically, the array consists of receptors spaced to cover the extent of each Class I area. Receptor elevations are included in the same NPS-provided receptor files.

5.1.5 Meteorological Data Processing

The refined 4-km grid resolution VISTAS CALMET files from sub-domain 2 were used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution MM5 data available for each year (i.e., 12-km MM5 data for 2001 and 2002 and 36-km MM5 data for 2003). A 4-km grid resolution is assumed to be adequate given the lack of significant terrain features in central Florida.

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish and Wildlife Service (FWS) using the current EPA regulatory version of CALMET (i.e., Version 5.8 Level 070623). Black & Veatch obtained this re-processed fine-grid CALMET dataset for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

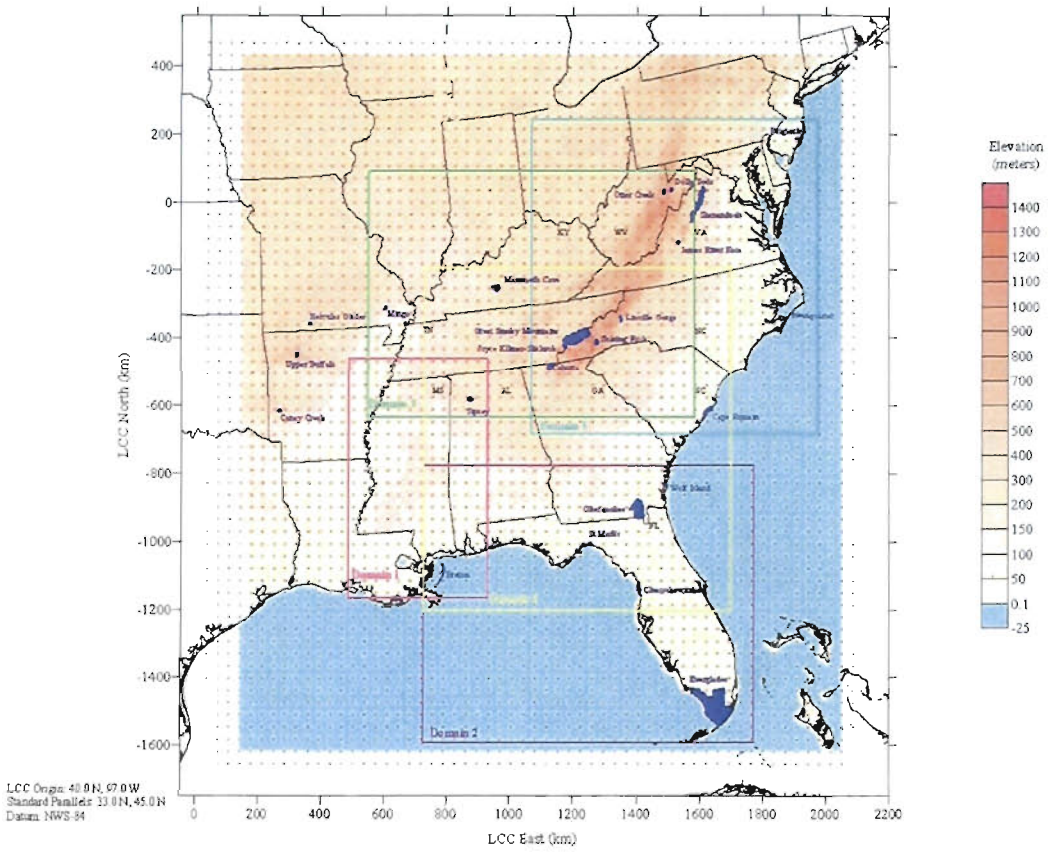

Figure 5-2
VISTAS 4-km CALMET Sub-Domains

Table 5-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, and speciated particulates.
Chemical Transformation	MESOPUFF II scheme.
Deposition	Include both dry and wet deposition, plume depletion.
Meteorological/Land Use Input	VISTAS CALMET files.
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration.
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME 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. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD SERs. Deposition: Annual total nitrogen and total sulfur deposition flux (including both wet and dry deposition).
Background Values	Ammonia: 0.5 ppb (monthly). Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. Monthly values were calculated using monthly averages from Everglades NP, Indian River Lagoon, and the Sumatra ozone monitors. These values are substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

CALMET Settings

The major features of CALMET used by Earth Tech to develop the CALMET files are listed below:

- Modeling period: 3 years (2001 – 2003).
- Meteorological inputs: MM5 data provide initial guess fields in CALMET. Meteorological observation data are used in the Step 2 calculations. Buoy data, hourly surface meteorological observations, precipitation observations, and twice-daily upper air sounding data were used.
- CALMET grid resolution: 4 km.
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: Refined mode with all available observational data included in the Step 2.
- Diagnostic options: IWAQM default values.
- CALMET options dealing with radius of influence parameters (R1 = 5 km, R2 = 5 km, RMAX1 = 40 km, RMAX2 = 40 km, RMAX3 = 100 km), BIAS(NZ) = 10*0, ICALM = 0 parameters were predetermined by Earth Tech.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments which was used for all years. Value of 15 km used.
- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great Lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter (MNMDAV = 1) was determined by Earth Tech for the regional simulations based on sensitivity tests.
- Geophysical data for regional runs: USGS 3-arcsec terrain data, and Composite Theme Grid USGS 200 m land use dataset.
- References for these and other CALMET datasets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

5.1.6 Modeling Domain

The CALPUFF modeling domain was a subset of the larger CALMET meteorological domain. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed project to the receptors at each of the Class I areas with at least a 50 km buffer zone in each direction. The modeling

analysis was performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40.0 and 97.0 degrees, respectively. A rectangular modeling domain extending 412 km in the east-west (x) direction and 432 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is located at 1,137.995 km Easting and -1,206 km Northing (LCC, NWS-84, 6,370 km Radius Global Sphere). The grid resolution for the domain was 4 km. A grid spacing of 4 km yields 103 grid cells in the x-direction and 108 grid cells in the y-direction. The size and location of the modeling domain was illustrated on Figure 5-1.

5.1.7 Project Emissions

The worst-case representative stack parameters and pollutants emission rates at 100 percent operating load were used in the CALPUFF analyses. This was accomplished by representing the 100 percent 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., 7, 59, 68.8, 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 (as H_2SO_4). Tables 4-1 and 4-2 contains the stack parameters and emission rates modeled in CALPUFF. Furthermore, in accordance with guidance from NPS, the PM/PM_{10} emissions were speciated based on size and composition for the regional haze analysis and therefore were broken into the following constituents: elemental carbon (EC) and organic carbon (OC) for natural gas operation and EC, Soils, and OC for fuel oil operation. Specifically, guidance from NPS on particulate matter speciation was found in the Emissions & Control Technology area of their Web site. In accordance with 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 the filterable portion of PM/PM_{10} emissions is considered EC and half is considered Soils and all non-$(NH_4)_2SO_4$ condensibles are considered to be OC.

The EC, OC, and Soils emissions were further speciated based on size. In accordance with NPS guidance, all particles were assumed to be one micron or less for combustion turbines. Tables 5-2, 5-3, and 5-4 present size distribution for EC, OC, and Soils particulates for natural gas CCCT operation, ULSFO CCCT operation, and ULSFO SCCT operation, respectively, as recommended by NPS along with the Project's emission rates for each category and size.

Table 5-2
Particle Speciation and Size Distribution for CCCT Natural Gas Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)	
			Filterable EC Emissions[a]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[b]
PM1P00	1.00	11	1.991	1.276
PM0P25	0.25	11	1.991	1.276
PM0P20	0.20	15	2.715	1.740
PM0P15	0.15	23	4.163	2.668
PM0P10	0.10	25	4.525	2.900
PM0P05	0.05	15	2.715	1.740
		Subtotals	18.10	11.60
		Total	29.70	

[a]Elemental Carbon (EC) includes all filterable emissions.
[b]Organic Carbon (OC) includes all condensable emissions.

Table 5-3
Particle Speciation and Size Distribution for CCCT ULSFO Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)		
			Filterable EC Emissions[a]	Soils[b]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[c]
PM1P00	1.00	11	1.166	1.166	2.156
PM0P25	0.25	11	1.166	1.166	2.156
PM0P20	0.20	15	1.590	1.590	2.940
PM0P15	0.15	23	2.438	2.438	4.508
PM0P10	0.10	25	2.650	2.650	4.900
PM0P05	0.05	15	1.590	1.590	2.940
		Subtotals	10.60	10.60	19.60
		Total	40.80		

[a]Elemental Carbon (EC) includes half of filterable emissions.
[b]Soils includes half of filterable emissions.
[c]Organic Carbon (OC) includes all condensable emissions.

Table 5-4
Particle Speciation and Size Distribution for SCCT ULSFO Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)		
			Filterable EC Emissions[a]	Soils[b]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[c]
PM1P00	1.00	11	0.935	0.935	1.870
PM0P25	0.25	11	0.935	0.935	1.870
PM0P20	0.20	15	1.275	1.275	2.550
PM0P15	0.15	23	1.955	1.955	3.910
PM0P10	0.10	25	2.125	2.125	4.250
PM0P05	0.05	15	1.275	1.275	2.550
		Subtotals	8.50	8.50	17.00
		Total	34.00		

[a]Elemental Carbon (EC) includes half of filterable emissions.
[b]Soils includes half of filterable emissions.
[c]Organic Carbon (OC) includes all condensable emissions.

5.2 CALPUFF Analyses Performed

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses at the five Class I areas, including regional haze, deposition, and Class I SILs. Electronic copies of Class I modeling input and output files are included in Attachment F.

5.2.1 Regional Haze Analysis

A regional haze analysis was performed for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions were speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

Visibility

Visibility is an AQRV for all Class I areas except BBW. As such, a visibility analysis was not be performed for BBW. 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 each of the Class I areas 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:

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} = Extinction coefficient calculated for the source.

b_{extb} = 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 follows:

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

Background Visual Ranges and Relative Humidity Factors

The background visual ranges are based on data representative of historical conditions at each of the Class I areas. The background visual ranges, or constituents thereof, for were obtained from the Phase I FLAG Report, December 2000. Relative humidity factors can come from various sources. The average relative humidity factor for each day can 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 hour's relative humidity can 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 hour of relative humidity) can then be used to determine the average relative humidity factor for that day (24-hour period). Alternately, the Phase I FLAG report provides seasonal relative humidity factors for each Class I area for direct input to the modeling analyses.

Interagency Workgroup on Air Quality Modeling Guidelines

The CALPUFF air modeling analysis followed the recommendations contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, (EPA, 12/98) where appropriate. Table 5-5 summarizes the IWAQM Phase II recommendations. CALPOST possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. Specifically, regional haze was first 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. The relative humidity for Method 2 was capped at 95 percent.

Then, as discussed with the FDEP on April 2, 2008, regional haze impacts were calculated using Method 6, which is similar to Method 2 except that seasonally averaged relative humidity adjustments are uses to compute the resultant extinctions. Method 6 is the preferred method for performing regional haze analyses by all of the regional planning organizations across the country (including VISTAS which covers the Southeastern states and is the origin of the meteorological database used in these analyses). Additionally, Method 6 is recommended by the USEPA's BART Guidance (70 FR 39162) as the accepted post-processing option. However, unlike the BART guidance and analyses, the results presented herein are conservatively based on the highest maximum model-predicted impacts rather than the 98th percentile impact (i.e., the 8th high impact). While the calculation of regional haze impacts occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 5-5
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	CALPUFF with default dispersion settings. Use MESOPUFF II chemistry with wet and dry deposition. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, PM_{10}, and NO_3 value; calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate.

Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM speciated (EC, OC, and Soils) 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:
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = 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
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 ($\mu g/m^3$) = 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
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   $b_{exts} = 3[NH_4NO_3]f(RH) + 3[(NH_4)_2SO_4]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]$
5. 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)
6. 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 speciated PM concentrations, the proposed Project's model-predicted impacts 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 5-6, the regional haze results using Method 6 (in conjunction with a reduction in daily hours of oil firing) are less than the 5 percent change in extinction threshold for each of the Class I areas and, as such, no further analysis is necessary. As stated above, the proposed Project is taking a reduction in the amount of daily hours of oil firing allowed in each CTG as a voluntary mitigation measure to ensure that model-predicted impacts from operations do not cause or contribute to degradation in visibility at the nearest Class I areas. Note that all other short-term modeling analyses presented throughout this application support document are conservatively performed without such daily restriction on oil firing as the impacts from the unrestricted daily operation remain below the requisite thresholds.

Table 5-6
Regional Haze Results

Class I Area	Change in Extinction[a] (%) Method 2 2001	Method 2 2002	Method 2 2003	Method 6 2001	Method 6 2002	Method 6 2003	Recommended Threshold (%)	Method 6 Exceed?
CCCT (Units 1 & 2), Gas – 24 hours per day								
Chassahowitzka	1.74	1.46	1.71	1.49	1.37	1.49	5	NO
Okefenokee	5.59	4.58	5.77	4.98	3.96	4.97	5	NO
St. Marks	0.96	1.44	1.49	1.02	1.24	1.36	5	NO
Wolf Island	2.02	2.31	2.19	2.14	2.03	1.73	5	NO
CCCT (Units 1 & 2), Oil – 24 hours per day								
Chassahowitzka	2.77	1.24	1.52	1.87	0.94	1.16	5	NO
Okefenokee	5.95	4.82	5.03	4.28	2.80	3.79	5	NO
St. Marks	0.93	1.69	1.44	0.62	1.16	1.13	5	NO
Wolf Island	2.10	2.98	2.30	1.40	1.83	1.45	5	NO

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

5.2.2 Deposition Analysis

Deposition analyses were performed at each Class I area 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:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 5.1 (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 to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), and seconds to a year to achieve CALPOST results 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. FWS for Class I areas located east of the Mississippi River. The results of the deposition analysis are presented in Table 5-7. As illustrated in the table, the deposition results for each Class I area are less than the 0.01 DAT and, as such, no further analysis is necessary.

5.2.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) at each Class I area 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 SILs calculated as 4 percent of the Class I Increment values. Table 5-8 presents the maximum results of the Class I analysis for the 3 year period modeled. As illustrated in the table, there are no impacts above the Class I SILs at any of the Class I areas and, as such, no further analysis is necessary.

Table 5-7
Deposition Results

Class I Area	Total Nitrogen Deposition[a] (kg/ha/yr)			Total Sulfur Deposition[b] (kg/ha/yr)			Deposition Analysis Threshold[c]
	2001	2002	2003	2001	2002	2003	
Chassahowitzka	2.89E-04	3.32E-04	2.06E-04	2.28E-04	2.79E-04	2.14E-04	1.0 E-02
Okefenokee	1.39E-03	1.79E-03	2.42E-03	7.75E-04	1.19E-03	1.77E-03	1.0 E-02
St. Marks	3.56E-04	5.77E-04	5.96E-04	2.44E-04	3.48E-04	4.38E-04	1.0 E-02
Wolf Island	7.41E-04	1.02E-03	1.18E-03	5.96E-04	9.27E-04	1.03E-03	1.0 E-02
Bradwell Bay	2.70E-04	4.49E-04	3.29E-04	1.57E-04	2.46E-04	2.17E-04	1.0 E-02

[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.

Table 5-8
Class I Significant Impact Levels Modeling Results

Pollutant	Fuel	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$)					PSD Class I SIL[b] ($\mu g/m^3$)	Exceed SILs?
			CW	OW	SMW	WIW	BBW		
NO_x	NG/ULSFO[c]	Annual	5.25E-04	3.94E-03	5.51E-04	1.75E-03	3.38E-04	0.10	NO
SO_2	NG/ULSFO[c]	Annual	2.21E-04	1.30E-03	2.06E-04	6.12E-04	1.37E-04	0.08	NO
	NG	24 Hour	6.56E-03	2.59E-02	5.31E-03	9.91E-03	3.33E-03	0.20	NO
	ULSFO	24 Hour	2.80E-03	8.81E-03	1.77E-03	3.36E-03	1.28E-03	0.20	NO
	NG	3 Hour	2.18E-02	5.83E-02	1.58E-02	3.92E-02	1.12E-02	1.00	NO
	ULSFO	3 Hour	7.95E-03	2.01E-02	6.26E-03	1.42E-02	4.44E-03	1.00	NO
PM/PM_{10}	NG/ULSFO[c]	Annual	1.05E-03	5.38E-03	1.08E-03	2.71E-03	7.74E-04	0.08	NO
	NG	24 Hour	2.91E-02	1.03E-01	2.71E-02	4.32E-02	2.08E-02	0.32	NO
	ULSFO	24 Hour	5.14E-02	1.38E-01	3.15E-02	5.26E-02	2.80E-02	0.32	NO

[a]Impacts represent the highest first high model-predicted concentration from all 3 years of meteorological data: 2001, 2002, and 2003 modeled at 100 percent load and include operation of the two CTGs.
[b] Class I SILs are calculated as 4 percent of the PSD Class I Increment values. Predicted impacts that are below the specified levels indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c] Impacts are from one of the annual modeling scenarios outlined in Section 2.

6.0 Additional Impact Analysis

A requirement of the PSD regulations is the need for an additional impact analysis as governed by Rule 62-212.400(4)(e), F.A.C., pertaining to the air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth that has occurred since August 7, 1977, in the area the Project would affect. A characterization of the population trend of the area can be a surrogate for general growth. An evaluation of the growth as it relates to the August 7, 1977 date, as well as a projection of growth indicators related to the Project with respect to workforce, housing, and commercial/industrial growth and their potential impact to air quality are presented below in Sections 6.1 through 6.4.

Additionally, Rule 62-212.400(8)(a), F.A.C., requires that an analysis that considers the impairment to visibility, soils, and vegetation that would occur as a result of the Project be performed. A visibility analysis was performed on four Class I areas and was provided in Section 5.0. Analyses for soils and vegetation were performed and are discussed in Section 6.5.

6.1 Growth Analysis

Jacksonville's current population of 794,555 (U.S Census Bureau 2006 estimate) makes it the largest city in Duval County (which has a total population of 837,964) although it is relatively small when compared to Florida's largest municipalities.

The population trends of Duval County may be used as a surrogate growth indicator of the extent of air quality impacts related to general commercial, residential, and industrial growth since August 7, 1977. The U.S. Census Bureau estimated that Duval County had a population of 559,300 persons in 1977. The Duval County population increased by 33.3 percent between 1977 and 2006, compared to a 50.9 percent growth for Florida over this same time period.

Since 1977, Duval County has successfully balanced growth and economic development with the preservation of unique environmental and recreational areas. The County has anticipated and planned for this additional growth while continuing to demonstrate compliance with the air quality standards (Duval County is in attainment for all criteria pollutants) and preserving the amenities offered to the county population and its visitors. Because the maximum predicted air pollutant concentrations for the proposed Project are well below the NSR/PSD significant impact levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when the proposed Project becomes operational. Therefore, from an air quality impact standpoint, the proposed facility is consistent with the balanced growth demonstrated by the county to date.

6.2 Workforce

Labor force statistics show that as of 2007 Duval County had a total employment of 540,120 persons. Major employment sectors in the county included the trade, transportation, and utilities sector (20.2 percent) as well as the professional and business services sector (15.8 percent). Education and health services (11.3 percent), financial activities (10.4 percent), government (9.6 percent) also made up a significant portion of the Duval County employment by industry in 2007.

County business data for Duval County for 1977 show the total employment to be 222,090 persons. The largest employment sector was in retail trade (18.9 percent). This was followed by government (18.7 percent), the services division (17.6 percent) and the manufacturing industry (12.1 percent). Other major employment sectors in the county included finance, insurance, real estate (11.4 percent), wholesale trade (8.1 percent), transportation, communications, and utilities (7.0 percent), and construction (5.8 percent). Non-classifiable establishments, agriculture, and the mining division make up the remainder of the sectors.

6.2.1 Workforce Growth Associated with the Project

The proposed Project will require a substantial construction workforce during the 18 month construction period to June 2012 time frame. During this period, an average of 127 direct craft construction workers and a total workforce (that also includes indirect craft workers, construction management, and local utility staff) average of 142 personnel are expected. The peak construction workforce is projected to occur during the 8th month of construction, when 231 direct craft workers, and a total of 246 workers, are expected onsite. However, the construction labor force increase and associated secondary air emissions increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the proposed Project.

The net number of new, permanent jobs that will be created by GEC is estimated at six. The secondary residential, commercial, and industrial growth associated with this small operation staff, which will be divided into shifts to provide around-the-clock operation, is not expected to have a significant impact on air quality.

6.3 Housing Growth Associated with the Project

The potential for housing shortages and thus the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (non-coal plants) like the proposed Project located in or near urban areas typically have no noticeable impacts on the housing market. The reason

is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the GEC site is considered, large metropolitan areas including Jacksonville and Gainesville are within commuting distance to the site, and a 100 mile radius includes cities like Daytona Beach and northern suburbs of Orlando.

The area offers a wide variety of temporary lodging, reflecting the area's status as a destination for recreational seekers. Given the expected population of the commuting workforce, the fact that during the 18 month construction period most workers will be onsite for less than the total construction period, and an abundance of hotel and other short-term lodging options in Duval County, it is unlikely that a substantial number of the construction workforce would choose to relocate during the 18 month construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

6.4 Commercial/Industrial Growth

The Project is being proposed to meet the existing and current projected electrical demands of the surrounding area. It is anticipated that little commercial growth will be associated with its specific operation. Additionally, the electrical generating capacity created by the CTGs will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be distributed to the grid as opposed to a nearby industrial host. For these reasons, the Project is not expected to have a significant impact on the air quality as the result of commercial or industrial growth.

6.5 Vegetation and Soils Analysis

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 vegetation and soils analysis was based on predicted air pollutant concentrations derived from a comprehensive air dispersion modeling analysis of the

emissions from the proposed Project. The model-predicted pollutant concentrations were compared to ambient air quality standards, which are designed to protect the public health, welfare, and the natural environment. These ambient air quality standards have been established by the USEPA for the six criteria air pollutants and include primary ambient air quality standards, which are designed to protect public health with an adequate margin of safety, and secondary ambient air quality standards, which are designed to protect public welfare-related values, including property, materials, and plant and animal life. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations of pollutants below the secondary AAQS will not result in harmful effects for most types of soils and vegetation. In Florida, ambient air quality standards at least as stringent as the national secondary standards have been adopted by the Department.

As given in Section 4.3 of the application, the model-predicted ambient concentrations of SO_2, PM/PM_{10}, NO_x, and CO are not only one or more orders of magnitude less than the applicable ambient air quality standards, but are even less than the more stringent NSR/PSD significant impact levels and the USEPA recommended screening levels for air pollution impacts on plants, soils, and animals. Because the predicted air quality impacts are so much lower than the air quality standards designed to protect plant and animal life, it is reasonable to conclude that the proposed emissions of SO_2, PM/PM_{10}, NO_x, and CO will not significantly affect vegetation, soils, or wildlife.

The air quality impact to soils, vegetation, and wildlife from H_2SO_4 is also expected to be insignificant. There is no national or state air quality standard for H_2SO_4 to compare model-predicted impacts with, as a general measure of H_2SO_4's air quality impact potential, as there are for other PSD pollutants. However, based on the fact that the Project proposes to use two of the least sulfur bearing fuels available (i.e., natural gas and ultra-low sulfur fuel oil) and that predicted SO_2 concentrations are orders of magnitude less than USEPA recommended screening concentrations, it is reasonable to assume that SAM emissions will not significantly impact the air quality in a manner that is detrimental to soils or vegetation.

To further demonstrate that the proposed Project will have an insignificant impact upon vegetation, additional modeling analyses were performed. Those analyses consisted of evaluating the Project's two largest emitted PSD pollutants (NO_x and CO) against the sensitive vegetation thresholds found in the EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals.* In that document, the minimum NO_2 concentrations at which adverse growth effects or tissue injury occurred for the most sensitive vegetation are: 3,760 ug/m^3 (4 hour averaging period), 564 ug/m^3 (1 month averaging period), and 94 ug/m^3 (1 year averaging period). Similarly, the most sensitive vegetation threshold for CO is given as 1,800,000 ug/m^3 (1 week averaging

period); potentially reducing the photosynthetic rate. The model-predicted impacts for these pollutants compared to the given thresholds are presented in Table 6-1. As illustrated in the table the proposed Project's impacts are significantly below the aforementioned screening levels and as such, no adverse impacts to vegetation at or near the facility are expected from NO_x and CO emissions.

The literature about air quality impacts on wildlife generally focuses on acute exposure by wildlife to unusual or high concentrations of pollutants. Wildlife can be affected through three pathways: ingestion, dermal exposure, and inhalation of ambient air, with ingestion, which can result in bioaccumulation, being the most common means of exposure to high concentrations of pollutants. However, the project air emissions and impacts are predicted to be very low, and are highly unlikely to have any effects on wildlife in the vicinity of the project.

Table 6-1
Additional Modeling Results to Assess Impacts to Vegetation

Pollutant	Averaging Period	Model-Predicted Impact[a] (ug/m^3)	Screening Threshold[b] (ug/m^3)	Exceed Threshold?
NO_x	4-hour	438.75	3,760	No
	24-hour	154.55	564	No
	1-month	35.97	94	No
CO	1-hour	81.70	1,800,000[c]	No

[a]Impacts represent the highest first high model-predicted concentration from the operation of the CTGs on ULSFO (since ULSFO has the highest short-term emissions for NO_x and CO) for all five years of meteorological data modeled at 100 percent load.
[b]Thresholds are taken from EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals.*
[c]Value is actually based on a 1 week averaging period. Model-predicted 1 hour impact is conservatively below this threshold.

Appendix A
FDEP Air Permit Application Forms

Department of Environmental Protection

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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 any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: JEA	
2. Site Name: Greenland Energy Center	
3. Facility Identification Number:	
4. Facility Location Street Address or Other Locator: 12121 Philips Hwy City: Jacksonville County: Duval Zip Code: 32258	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: N. Bert Gianazza, P.E.
2. Application Contact Mailing Address... Organization/Firm: JEA (Tower-8) Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
3. Application Contact Telephone Numbers... Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Application Contact Email Address: giannb@jea.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 9/16/08	3. PSD Number (if applicable): 405
2. Project Number(s): 0310541-007-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

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

JEA is proposing to convert the two simple cycle combustion turbines (CTs) at the Greenland Energy Center (GEC) into a 2 x 1 combined cycle configuration. The GEC is located in southeastern Duval County, Florida and is currently undergoing construction permitting for the two simple cycle units. The combined cycle configuration will consist of the same two General Electric (GE) 7FA combustion turbines that are currently being permitted as simple cycle units, but will now each include a heat recovery steam generator with supplemental natural gas-fired duct burners. The simple cycle functionality of each combustion turbine will be retained post-combined cycle conversion. The currently proposed simple cycle combustion turbine stack will function as a bypass stack when the combustion turbines are operating in a simple cycle mode. The proposed conversion project will include only the combined cycle conversion of the simple cycle units with no further additions to the ancillary units already included, and currently being permitted as part of the simple cycle operations.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
EU01	GE 7FA Combined Cycle Combustion Turbine	AC1A	$7,500
EU02	GE 7FA Combined Cycle Combustion Turbine	AC1A	NA
EU03	Linear Mechanical Draft Cooling Tower	AC1A	NA

Application Processing Fee

Check one: [x] Attached - Amount: $ 7,500 [ ] 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 :
   Mr. James M. Chansler, P.E., D.P.A., Chief Operating Officer
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: JEA
   Street Address: 21 West Church Street
   City: Jacksonville State: FL Zip Code: 32202
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: (904) 665-4433 ext. Fax: (904) 665-7990
4. Owner/Authorized Representative Email Address:
5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.

James M. Chansler

Signature

9/10/08

Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation 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, CAIR source, or Hg Budget 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 E-mail 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: N. Bert Gianazza
   Registration Number: 38640
2. Professional Engineer Mailing Address...
   Organization/Firm: JEA (Tower-8)
   Street Address: 21 West Church Street
   City: Jacksonville State: FL Zip Code: 32202
3. Professional Engineer Telephone Numbers...
   Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Professional Engineer Email Address: giannb@jea.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 9/10/08 Date

(seal)

* 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) 450.218 North (km) 3336.391		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: N. Bert Gianazza, P.E. – Environmental Services
2. Facility Contact Mailing Address... Organization/Firm: JEA (Tower-8) Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Facility Contact Email Address: giannb@jea.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. [X] Title V Source	
4. [x] 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. [X] 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]?
NOX	A	N
CO	A	N
VOC	B	N
SO2	A	N
PM	A	N
PM10	A	N
SAM	A	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. 1 [ ] 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. 2 [ ] 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. 3 [ ] Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   [x] Attached, Document ID: See Figure 2-1 of Application Support Document
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):
   [x] Attached, Document ID: See Section 2.0 of the Application Support Document
3. Rule Applicability Analysis:
   [X] Attached, Document ID: Attach. 4
4. List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.):
   [x] Attached, Document ID: Attach 5 [ ] Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification:
   [ ] Attached, Document ID:_____ [X] Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.):
   [ ] Attached, Document ID: See Section 4, 5, 6 of the Application Support Document
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.):
   [ ] Attached, Document ID: See Section 4, 5 and 6 of the Application Support Document
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):
   [ ] Attached, Document ID: See Section 6 of the Application Support Document
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):
   [ ] Attached, Document ID: See Section 6 of the Application Support Document
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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   [x] Attached, Document ID: See Attach. 9 [ ] Previously Submitted, Date:_____
   [ ] Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [x] Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [x] Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [x] Not Applicable (not a CAIR source)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
   [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [x] Not Applicable (not a Hg Budget unit) – CAMR Vacated

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in the Application Support Document. Please see Appendix F of the application package.

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.

EMISSIONS UNIT INFORMATION
Section [1] of [2]

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.

☐ 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: 2 x1 Combined Cycle Power Block consisting of: Natural Gas/Ultra-Low Sulfur Fuel Oil fired Combustion Turbine Generators (CTGs) 1 and 2; Each CTG has a gross rating of 170 MW while firing natural gas and 180 MW while firing ultra low sulfur fuel oil (ULSFO), at an ambient temperature of 59°F (ISO conditions). Each CTG will have a heat recovery steam generator (HRSG) with a 189 MBtu/hour (HHV) natural gas fired supplementary duct burners. The two CTG/HRSGs will provide steam to a steam turbine generator (STG).

3. Emissions Unit Identification Number: EU01 and EU02

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 ☐ No

9. Package Unit:
Manufacturer: General Electric Model Number: PG7241 7FA

10. Generator Nameplate Rating: The 2 x 1 Power Block will generate a gross output of 563 MW when firing gas and 541 MW when firing ULSFO, at ISO conditions.

11. Emissions Unit Comment:
Natural gas firing gross output: Each CTG: 170 MW, STG: 223 MW. Total: 563 MW
ULSFO firing gross output: Each CTG: 180 MW, STG: 181 MW. Total: 541 MW
When auxiliary power is subtracted, the nominal power output for the 2 x 1 power block will be 547 MW when firing natural gas, and 524 MW when firing ULSFO (duct burners off).

Emissions Unit Control Equipment

1. Control Equipment/Methods Description:
   Dry low NO_x(DLN) burners and SCR used to control NO_x when firing natural gas.
   DLN burners, SCR and water injection used to control NO_x when firing ULSFO.

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: Firing natural gas, 100% load, 7 °F: CTG: 1,948 MBtu/hr (HHV) Duct burner: 189 MBtu/hr (HHV)	Maximum Heat Input Rate: Firing ULSFO, 100% load, 7 °F: CTG: 2,101 MBtu/hr (HHV) Duct burner (firing gas): 189 MBtu/hr (HHV)
4. Maximum Incineration Rate: pounds/hr tons/day	

5. Requested Maximum Operating Schedule:

Each CTG firing natural gas: 24 hours/day, 52 weeks/year and 8,760 hours per year

Each duct burner firing natural gas: 24 hours/day, 52 weeks/year and 8,760 hours per year

Each CTG Firing ULSFO for 24 hrs/day and up to 500 hours per year.

All simple cycle operational scenarios are unchanged from the permit application (ref: DEP File No. 0310561-001-AC (PSD –FL-401)

One turbine can operate in combined cycle mode while the other is operating in a simple cycle mode. Please refer to the application support document for more details on the operational scenario matrix.

6. Operating Capacity/Schedule Comment:

The two combined cycle combustion turbines will be operated between 50 and 100 percent of full load. The maximum heat input shown in Field 3 is with operation at 100 percent load at the site minimum ambient temperature of 7°F. Operation at 100 percent load and at 59°F is expected to have a corresponding maximum per CTG heat input of 1,778 MBtu/hr and 1,948 MBtu/hr (HHV) for natural gas and ULSFO, respectively. Note that the heat input rates are a function of operating parameters and ambient conditions.

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: Combustion Turbine No. 1 and Combustion Turbine No. 2	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

Each CTG/HRSG discharges through a 160-foot vertical cylindrical exhaust stack. Each CTG will also have the capability to exhaust through the 115-foot bypass stack (currently being permitted as the simple cycle exhaust stack).

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
N/A

5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 18 feet
8. Exit Temperature: (ISO) 194 °F (natural gas); 324 °F (ULSFO)	9. Actual Volumetric Flow Rate: 1,014,853 acfm (natural gas, ISO) 1,281,185 acfm (ULSFO, ISO)	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate:	12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... East (km): 450.269 (Unit 1); 450.269 (Unit 2) North (km):3336.445 (Unit 1); 3336.391 (Unit 2)	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

Exit temperature and flow rate are with operation of <u>each</u> CTG/HRSG at 100 percent load with duct firing and at ISO conditions.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): Natural gas used in each of the two combustion turbines		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 1.94 (approx.)	5. Maximum Annual Rate: 15,544 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1,002 (HHV)

10. Segment Comment:

Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(1,948 MBtu/hr)/(1,002 MBtu/million scf) = 1.94 million scf/hour **(per CTG)**

Maximum Annual Rate:
[(1,778 MBtu/hr)/(1,002 MBtu/million scf)] x (8,760 hr/yr) = 15,544 million scf/yr **(per CTG)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature and 8,760 hours of natural gas firing in each of the two combustion turbines.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): ULSFO used in each of the two combustion turbines		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 15.22 per CTG	5. Maximum Annual Rate: 7,058 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 138 (HHV)

10. Segment Comment:

Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(2,101 MBtu/hr)/(138 MBtu/kgal) = 15.22 kgal/hour **(per CTG)**

Maximum Annual Rate:
[(1,948 MBtu/hr)/(138 MBtu/kgal)]x(500 hr/yr) = 7,058 kgal/yr **(per CTG)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature. In the combined cycle operational mode, the two CTGs will each operate up to 500 hours per year on ULSFO

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): Natural gas used in the duct burners in each HRSG.		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.189 (approx.)	5. Maximum Annual Rate: 1,652 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1,002 (HHV)

10. Segment Comment:
Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(189 MBtu/hr)/(1,002 MBtu/million scf) = 0.189 million scf/hour **(per HRSG)**

Maximum Annual Rate:
[(189 MBtu/hr)/(1,002 MBtu/million scf)] x (8,760 hr/yr) = 1,652 million scf/yr **(per HRSG)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature and 8,760 hours of natural gas firing in each of the duct burners in each of the two HRSGs.

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
NOX	**139, 205**	**028** (only while firing ULSFO)	**EL**
CO			**EL**
VOC			**NS**
SO2			**WP**
PM			**NS**
PM10			**NS**
SAM			**WP**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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: See Appendix C of the application support document for emission calculations	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions:
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating on natural gas at greater than 75 percent load. Emissions from natural gas fired duct burners in the HRSG are included.	

Allowable Emissions Allowable Emissions 2 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions:
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating on ULSFO at greater than 75 percent load. Emissions from natural gas fired duct burners in the HRSG are included.	

Allowable Emissions Allowable Emissions 3 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 96 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating at less than 75 percent load.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 5

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 14.2 lb/hour per CTG (natural gas operation)
5. Method of Compliance: CEMS, 24-hour block average; Stack test 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits. Emissions from natural gas fired duct burners in the HRSG are included.	

Allowable Emissions Allowable Emissions 5 of 5

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 8.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 66.7 lb/hour (ULSFO)
5. Method of Compliance: CEMS, 24-hour block average; Stack test, 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: 7.6 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 32.7 lb/hour (natural gas firing)
5. Method of Compliance: Stack test, 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits. Emissions from natural gas fired duct burners in the HRSG are included.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 8.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 40.6 lb/hour (ULSFO firing)
5. Method of Compliance: CEMS, 24-hour block average, Stack test 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits. Emissions from natural gas fired duct burners in the HRSG are included.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: 10 percent opacity at HRSG stack	4. Equivalent Allowable Emissions:
5. Method of Compliance: Annual Visible Emissions Test Using USEPA Method 9, when firing natural gas	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 percent opacity at HRSG stack	4. Equivalent Allowable Emissions:
5. Method of Compliance: Annual Visible Emissions Test Using USEPA Method 9, when firing ULSFO	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO.	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: Use of natural gas with less than 20 grains sulfur per 100 standard cubic feet	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Natural gas supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The natural gas sulfur standard is associated with NSPS Subpart KKKK. Per 40 CFR 60.4365, JEA is requesting that they be exempt from the requirement to monitor fuel sulfur content by demonstrating the fuel sulfur content through the natural gas tariff sheet.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The fuel oil sulfur standard is associated with NSPS Subpart KKKK. Per 40 CFR 60.4365, JEA is requesting that they be exempt from the requirement to monitor fuel sulfur content by demonstrating the fuel sulfur content through the fuel oil purchase contract.	

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: 0.0015 percent sulfur content by weight	4. Equivalent Allowable Emissions:
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 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: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: Natural gas with 2 grains per 100 scf	4. Equivalent Allowable Emissions:
5. Method of Compliance: Natural gas supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015 percent sulfur in ULSFO	4. Equivalent Allowable Emissions:
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO.	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G 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: VE10	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Maximum Period of Excess Opacity Allowed:	Exceptional Conditions: min/hour
4. Method of Compliance: Annual USEPA Method 9 test	
5. Visible Emissions Comment: Proposed as PM BACT	

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 Subsection H 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: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: TBD	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: Rule: 40 CFR 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	[ ] Rule [x] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Needed for compliance with CO BACT limit.	

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. 2 [ ] 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. 6 [ ] 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: See Section 3 of the Application Support Document

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. 7 [ ] 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(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   [x] Attached, Document ID: See Section 3 of the Application Support Document
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: See Section 4 of the Application Support Document
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   [x] Attached, Document ID: See Attach. 8 [ ] 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

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in Appendix F of the application package.

EMISSIONS UNIT INFORMATION
Section [2] of [2]

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.

☒ 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:
8-Cell Linear Mechanical Draft Cooling Tower.

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 ☒ 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: 135,300 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	7 days/week
52 weeks/year	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: 13.75 ft (top of deck)	7. Exit Diameter: 28 ft
8. Exit Temperature: 101.92 °F	9. Actual Volumetric Flow Rate: 1,225,000 cfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:	12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): North (km):	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: 8,118	5. Maximum Annual Rate: 71,113,680	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 Subsection F1 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/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.97 lb/hour 4.26 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 = 135,300 gpm = 67,704,120 lb/hr
Design drift rate = 0.0005% of design water flow
Total dissolved solids = 2,875 ppm
Hourly PM/PM10 emissions = 67,704,120 lb/hr x 0.0005/100 x 2,875 ppm/1,000,000 = 0.97 lb/hr
The maximum annual PM/PM10 emissions = 0.97 lb/hr x 8,760 hr/yr x ton/2,000 lb = 4.26 tpy

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G 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 Subsection H 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. 2 [ ] 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: See Section 3 of Application Support Document

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. 7 [ ] 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

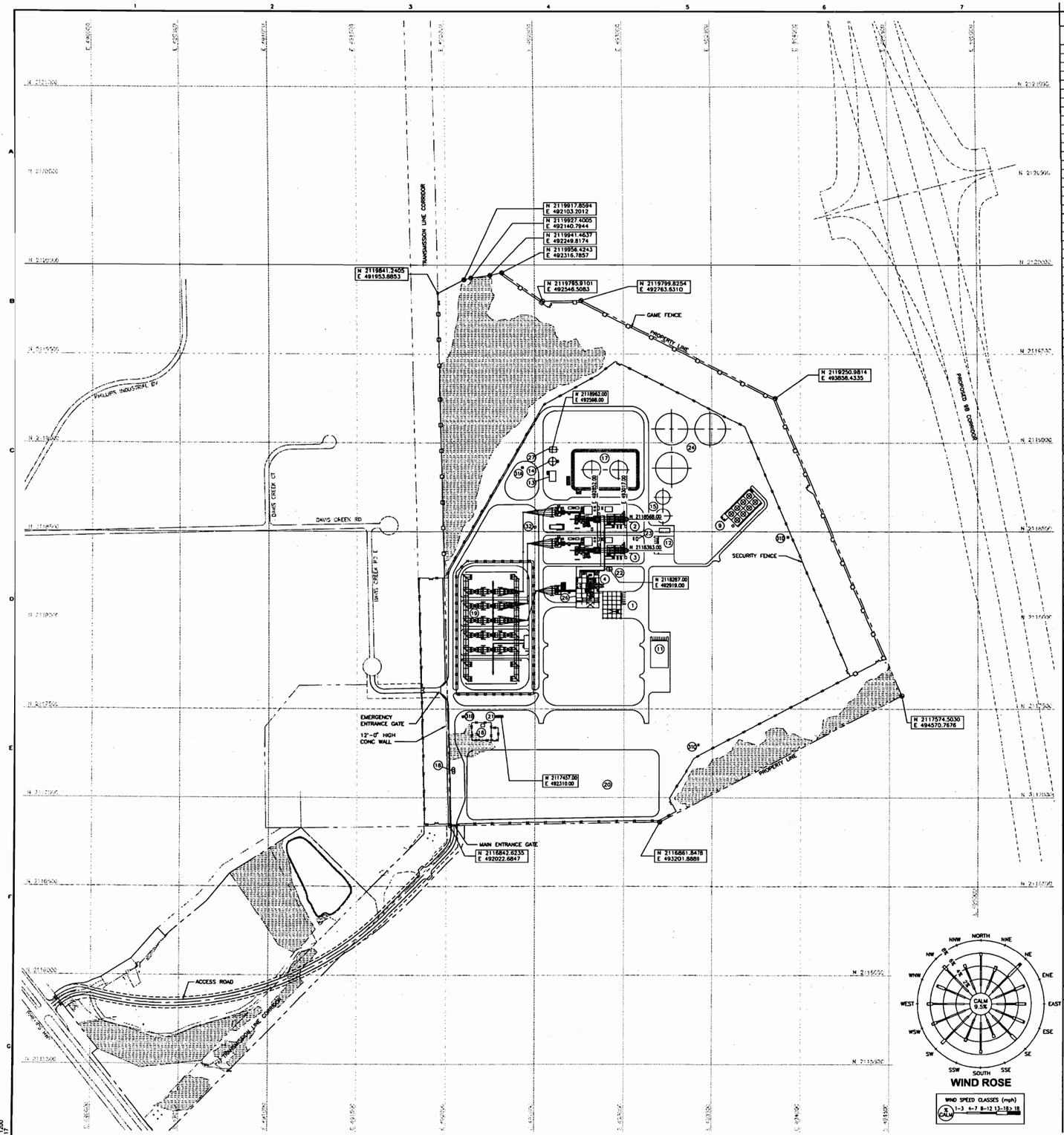
1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   [x] Attached, Document ID: See Section 3 of the Application Support Document
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: See Section 4 of Application Support Document
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

Additional Requirements Comment

Attachment 1
Facility Plot Plan



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	LOCATION COORDINATES EAST	REFERENCE LOCATION
1	ADMIN/CONTROL/MAINTENANCE BUILDING (26,250 SF)			
2	COMBUSTION TURBINE NO 1			CL STACK
3	COMBUSTION TURBINE NO 2			CL STACK
4	STEAM TURBINE NO 3			
5				
6				
7				
8				
9	COOLING TOWER			NE CORNER
10				
11	WAREHOUSE (14,000 SF)			
12	WATER TREATMENT BUILDING (9,000 SF)			
13	AMMONIA STORAGE TANK & TRANSFER PUMPS			
14	SERVICE / FIRE WATER TANK			
15	DEMIN WATER TANKS - 3 DAY STORAGE (1,600,000 GAL TOTAL)			
16	GAS METERING STATION			
17	FUEL OIL TANKS W/CONTAINMENT (3,750,000 GAL TOTAL)			
18	GUARD SHACK			
19	230 KV SUBSTATION			
20	DETENTION POND			
21	FUEL GAS HEATER			CL STACK
22	DIESEL GENERATOR			CL STACK
23	OIL WATER SEPARATOR			
24	REUSE SURGE TANK (5,000,000 GAL)			
25				
26	STEAM TURBINE BUILDING			
27	FIRE PUMP BUILDING			CL STACK
28				
29				
30				
31A	ABOVE-GRADE MONITORING WELLS (SEE DWG 160167-DS-0055)	2118860	492430	
31B	ABOVE-GRADE MONITORING WELLS (SEE DWG 160167-DS-0055)	2117457	492094	
31C	ABOVE-GRADE MONITORING WELLS (SEE DWG 160167-DS-0055)	2117297	493418	
31D	ABOVE-GRADE MONITORING WELLS (SEE DWG 160167-DS-0055)	2118468	493930	
32	UTILITY TIE-INS			

GENERAL LEGEND

7' HIGH CHAIN LINK SECURITY FENCE
8' HIGH GAME FENCE
PROPERTY LINE

REFERENCE DRAWINGS

1.
2.
3.
4.
5.
6.
7.

NOTES

1.

FOR PERMITTING USE ONLY

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0		PERMITTING ISSUE	DS	DS		TD	DG

SCALE: 1"=200'

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.

ENGINEER TPO DRAWN DAS
CHECKED DATE

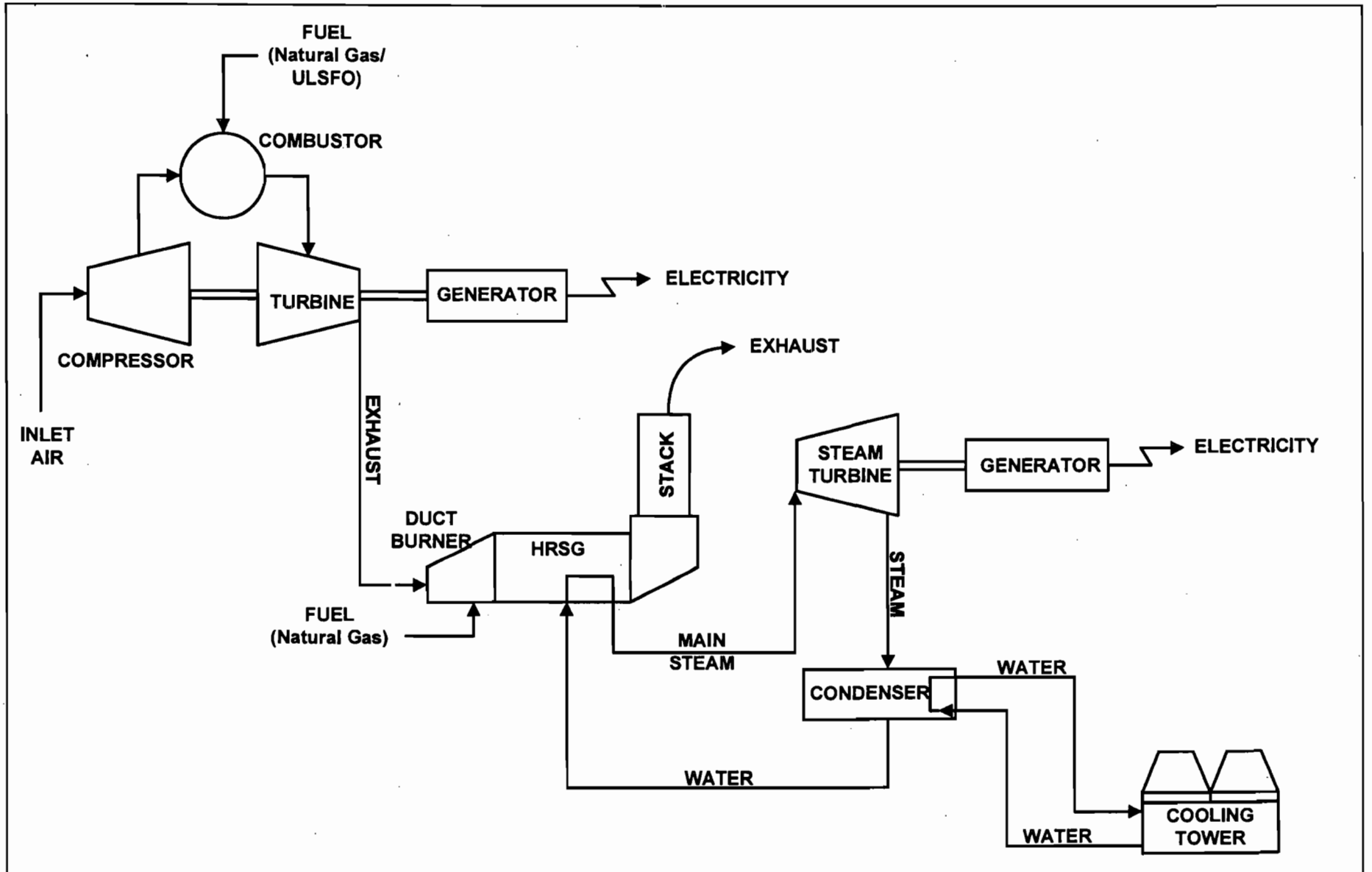
JEA
GREENLAND ENERGY CENTER

SITE ARRANGEMENT - COMBINED CYCLE
UNITS 1, 2 & 3

PROJECT DRAWING NUMBER 160167-DS-0007 REV 0
CODE
AREA
CERTIFICATE OF AUTHORIZATION NO. 8132

SYM52704 ACAD 16.1s (LMS Tech)
A1ASL017 E1 1200
07/09/08 13:58:17

Attachment 2
Process Flow Diagram



Greenland Energy Center
Combined Cycle Combustion Turbine
Process Flow Diagram

Attachment 3
Precautions to Prevent Emissions of Unconfined Particulate Matter

Attachment 3
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 4
Rule Applicability Analysis

Attachment 4
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 Turbines Units 1 and 2

The following rules are not applicable to the Project:

1. 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 GEC is not and will not be a major source of HAPs after the project, 40 CFR 63 Subpart YYYY does not apply to the combustion turbine.

2. NOT APPLICABLE - Federal: 40 CFR Part 60 Subpart GG (Rule 62-204.800(8)(b).39) – *Standards of Performance for Stationary Gas Turbines.* Because the two combined cycle combustion turbines are each subject to NSPS Subpart KKKK, they are not subject to Subpart GG.

3. NOT APPLICABLE - 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.* Since the combined cycle combustion turbines, including the duct burners are subject-to the requirements of NSPS Subpart KKKK, NSPS Subpart Da is not applicable.

4. NOT APPLICABLE - 40 CFR Part 60 Subpart Kb – *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.* The distillate fuel oil tanks each have a capacity greater than or equal to 40,000 gallons (151 cubic meters) and store a liquid with a maximum true vapor pressure less than 3.5 kPa, and are therefore not subject to Subpart Kb.

5. The Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) have been vacated at the federal level and as such are not applicable. As such, these programs are further presumed to be not applicable at the State level.

The following rules are applicable to the Project:

1. State: Rule 62-212.400 – *Prevention of Significant Deterioration* applies since the potential emissions of certain PSD applicable pollutants are greater than the PSD major source thresholds.
2. Federal: 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Gas Turbines*
3. Federal: 40 CFR Part 60 Subpart A – *General Provisions.*
4. Federal: 40 CFR Part 72 – *Permits Regulation (Acid Rain)*
5. Federal: 40 CFR Part 75 – *Continuous Emissions Monitoring*
6. State: Rule 62-204.800(8)(d) – *General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions.*
7. State: Rule 62-212.300 – *General Preconstruction Review Requirements.* Applies to all pollutants.
8. State: Rule 62-297.310 – General Compliance Test Requirements.

Attachment 5
List of Exempt Units

Attachment 5
List of Exempt Emission Units

There are no new exempt emission units being installed as part of the combined cycle conversion project.

Attachment 6
Fuel Analysis or Specification

Attachment 6
Fuel Analysis or Specification

Fuel is specified as pipeline natural gas or ultra low sulfur No. 2 fuel oil containing no more than 0.0015 percent sulfur.

Attachment 7
Operation and Maintenance Plan

Attachment 7
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 8
Description of Stack Sampling Facilities

Attachment 8
Description of Stack Sampling Facilities

Units 1 and 2 will be equipped with stack sampling facilities appropriate for performing required stack testing during operations in both simple cycle and combined cycle modes. 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 9
Acid Rain Forms

Attachment 9
Acid Rain Forms

A completed Acid Rain application for GEC was filed with the FDEP in June 2008.

Appendix B
Combined Cycle Combustion Turbine Performance Data

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Combined Cycle Emissions, Revision 1

Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Ambient Conditions																
Ambient Temperature, F	7.0	7.0	7.0	7.0	59.0	59.0	59.0	59.0	68.8	68.8	68.8	68.8	105.0	105.0	105.0	105.0
Ambient Relative Humidity, %	74.0	74.0	74.0	74.0	60.0	60.0	60.0	60.0	73.4	73.4	73.4	73.4	35.3	35.3	35.3	35.3
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	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	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	7.0	7.0	7.0	7.0	59.0	59.0	59.0	59.0	68.8	68.8	68.8	68.8	105.0	105.0	105.0	105.0
CTG Compr. Inlet Relative Humidity, %	74.2	74.2	74.2	74.2	60.1	60.1	60.1	60.1	73.5	73.5	73.5	73.5	35.4	35.4	35.4	35.4
Inlet Loss, in. H2O	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Exhaust Loss, in. H2O	18.8	18.8	11.9	8.0	16.0	16.0	10.6	7.4	15.3	15.3	10.3	7.2	12.9	12.9	9.2	6.5
CTG Load Level (percent of Base Load)	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
Gross CTG Output, kW	189,763	189,763	142,322	94,881	169,552	169,552	127,164	84,776	164,693	164,693	123,520	82,346	141,725	141,725	106,294	70,863
Gross CTG Heat Rate, Btu/kWh (LHV)	9,253	9,253	10,000	11,913	9,455	9,455	10,292	12,340	9,532	9,532	10,416	12,466	9,963	9,963	11,093	13,177
Gross CTG Heat Rate, Btu/kWh (HHV)	10,264	10,264	11,093	13,215	10,488	10,488	11,417	13,689	10,574	10,574	11,554	13,828	11,052	11,052	12,305	14,617
CTG Heat Input, MBtu/h (LHV)	1,755.9	1,755.9	1,423.2	1,130.3	1,603.1	1,603.1	1,308.8	1,046.1	1,569.9	1,569.9	1,286.6	1,026.5	1,412.0	1,412.0	1,179.1	933.8
CTG Heat Input, MBtu/h (HHV)	1,947.8	1,947.8	1,578.8	1,253.9	1,778.3	1,778.3	1,451.8	1,160.5	1,741.4	1,741.4	1,427.2	1,138.7	1,566.3	1,566.3	1,308.0	1,035.8
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	3,964,000	3,964,000	3,109,000	2,522,000	3,612,000	3,612,000	2,910,000	2,407,000	3,530,000	3,530,000	2,869,000	2,381,000	3,207,000	3,207,000	2,700,000	2,270,000
CTG Exhaust Temperature, F	1,063	1,063	1,125	1,178	1,116	1,116	1,161	1,200	1,127	1,127	1,169	1,200	1,168	1,168	1,200	1,200
Combustion Turbine Fuel																
Total CTG Fuel Flow, lb/h	84,350	84,350	68,370	54,300	77,010	77,010	62,870	50,260	75,420	75,420	61,810	49,310	67,830	67,830	56,640	44,860
CTG Fuel Temperature, F	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	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	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00

07/03/08
JEA
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Combined Cycle Emissions, Revision 1

Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust																
CTG Exhaust Analysis (Volume Basis - Wet)																
Ar	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.93%	0.94%	0.93%	0.93%	0.93%	0.93%	0.92%	0.92%	0.92%	0.92%
CO2	3.73%	3.73%	3.85%	3.77%	3.72%	3.72%	3.77%	3.65%	3.72%	3.72%	3.75%	3.61%	3.67%	3.67%	3.64%	3.43%
H2O	7.37%	7.37%	7.61%	7.46%	8.20%	8.20%	8.29%	8.05%	8.90%	8.90%	8.96%	8.69%	9.69%	9.69%	9.64%	9.24%
N2	75.07%	75.07%	74.98%	75.04%	74.43%	74.43%	74.39%	74.48%	73.88%	73.88%	73.85%	73.96%	73.22%	73.22%	73.24%	73.40%
O2	12.88%	12.88%	12.62%	12.79%	12.72%	12.72%	12.61%	12.88%	12.57%	12.57%	12.51%	12.82%	12.50%	12.50%	12.56%	13.01%
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%
SO3, (after SO2 oxidation)	0.00002%	0.00002%	0.00003%	0.00003%	0.00002%	0.00002%	0.00003%	0.00002%	0.00002%	0.00002%	0.00003%	0.00002%	0.00002%	0.00002%	0.00002%	0.00002%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.50	28.50	28.49	28.50	28.41	28.41	28.40	28.42	28.33	28.33	28.33	28.35	28.24	28.24	28.25	28.27
Specific Volume, ft^3/lb	37.30	37.30	39.48	41.17	38.97	38.97	40.61	41.89	39.42	39.42	40.95	42.02	40.80	40.80	41.97	42.20
Specific Volume, scf/lb	13.31	13.31	13.32	13.31	13.35	13.35	13.36	13.35	13.39	13.39	13.39	13.38	13.43	13.43	13.43	13.42
Exhaust Gas Flow, acfm	2,464,287	2,464,287	2,045,722	1,730,512	2,345,994	2,345,994	1,969,585	1,680,487	2,319,210	2,319,210	1,958,093	1,667,494	2,180,760	2,180,760	1,888,650	1,596,567
Exhaust Gas Flow, scfm	879,347	879,347	890,198	559,464	803,670	803,670	647,960	535,558	787,778	787,778	640,265	530,963	717,834	717,834	604,350	507,723
CTG NOx Emissions (Without Post Combustion Emissions Control)																
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.79	0.14	0.00	0.00	0.66	0.46
Additional Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd (dry)	10.64	10.64	11.02	10.77	10.72	10.72	10.87	10.49	10.80	10.80	10.89	10.45	10.75	10.75	10.65	10.00
NOx, ppmvw (wet)	9.85	9.85	10.18	9.97	9.84	9.84	9.97	9.64	9.84	9.84	9.92	9.54	9.71	9.71	9.63	9.08
NOx, lb/h as NO2	63.1	63.1	51.1	40.6	57.6	57.6	47.0	38.0	56.4	56.4	47.0	37.0	50.7	50.7	43.0	34.0
NOx, lb/MBtu (LHV)	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0363	0.0359	0.0359	0.0365	0.0360	0.0359	0.0359	0.0365	0.0364
NOx, lb/MBtu (HHV)	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0327	0.0324	0.0324	0.0329	0.0325	0.0324	0.0324	0.0329	0.0328
CTG CO Emissions (Without Post Combustion Emissions Control)																
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate, lb/h	0.00	0.00	0.00	0.35	0.00	0.00	0.31	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	6.56	4.10	7.35	7.52	6.46	4.10	7.45	7.72	6.44	4.10	7.44	7.75	6.31	4.10	7.60	8.10
CO, ppmvd (dry)	7.75	4.85	9.00	9.00	7.70	4.88	9.00	9.00	7.72	4.92	9.00	9.00	7.53	4.90	9.00	9.00
CO, ppmvw (wet)	7.18	4.49	8.31	8.33	7.07	4.48	8.25	8.28	7.03	4.48	8.19	8.22	6.80	4.42	8.13	8.17
CO, lb/h	28.0	17.5	25.4	21.0	25.2	16.0	24.0	20.0	24.6	15.6	23.2	19.3	21.6	14.1	22.0	18.4
CO, lb/MBtu (LHV)	0.0159	0.0100	0.0179	0.0186	0.0157	0.0100	0.0183	0.0191	0.0156	0.0100	0.0181	0.0188	0.0153	0.0100	0.0187	0.0197
CO, lb/MBtu (HHV)	0.0144	0.0090	0.0161	0.0167	0.0141	0.0090	0.0165	0.0172	0.0141	0.0090	0.0163	0.0170	0.0138	0.0090	0.0168	0.0177
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)																
SO2 massflow (lb/h) added to match CTG manufacturer's lb/h SO2 emissions estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094	0.9094
SO2, ppmvd (dry)	1.0750	1.0750	1.1133	1.0885	1.0833	1.0833	1.0987	1.0597	1.0910	1.0910	1.1007	1.0556	1.0860	1.0860	1.0766	1.0107
SO2, ppmvw (wet)	0.9958	0.9958	1.0285	1.0073	0.9945	0.9945	1.0076	0.9743	0.9939	0.9939	1.0021	0.9639	0.9807	0.9807	0.9729	0.9173
SO2, lb/h	8.8721	8.8721	7.1913	5.7114	8.1000	8.1000	6.6128	5.2864	7.9328	7.9328	6.5013	5.1865	7.1345	7.1345	5.9575	4.7184
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Combustion Turbine Exhaust - continued																
CTG UHC Emissions (Without Post Combustion Emissions Control)																
UHC massflow (lb/h) added to match CTG manufacturer's lb/h CO emissions estimate	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	6.4	6.4	6.2	6.3	6.4	6.4	6.3	6.5	6.4	6.4	6.4	6.6	6.5	6.5	6.5	6.9
UHC, ppmvd (dry)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.8	7.8	7.7	7.7
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	15.6	15.6	12.3	10.0	14.3	14.3	11.5	9.5	14.0	14.0	11.4	9.4	12.8	12.8	11.0	9.0
UHC, lb/MBtu as CH4 (LHV)	0.0089	0.0089	0.0086	0.0088	0.0089	0.0089	0.0088	0.0091	0.0089	0.0089	0.0088	0.0092	0.0090	0.0090	0.0093	0.0097
UHC, lb/MBtu as CH4 (HHV)	0.0080	0.0080	0.0078	0.0080	0.0080	0.0080	0.0079	0.0082	0.0080	0.0080	0.0080	0.0083	0.0081	0.0081	0.0084	0.0087
CTG VOC Emissions (Without Post Combustion Emissions Control)																
VOC Massflow (lb/h) added to match CTG manufacturer's lb/h VOC emissions estimate	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4
VOC, ppmvd (dry)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.5	1.5
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	3.1	3.1	2.5	2.0	2.9	2.9	2.3	1.9	2.8	2.8	2.3	1.9	2.6	2.6	2.2	1.8
VOC, lb/MBtu as CH4 (LHV)	0.0018	0.0018	0.0017	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0019	0.0019
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0017	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%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0051	0.0051	0.0063	0.0080	0.0056	0.0056	0.0069	0.0086	0.0057	0.0057	0.0070	0.0088	0.0064	0.0064	0.0076	0.0096
PM10, lb/MBtu (HHV)	0.0046	0.0046	0.0057	0.0072	0.0051	0.0051	0.0062	0.0078	0.0052	0.0052	0.0063	0.0079	0.0057	0.0057	0.0069	0.0087
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0103	0.0103	0.0126	0.0159	0.0112	0.0112	0.0138	0.0172	0.0115	0.0115	0.0140	0.0175	0.0127	0.0127	0.0153	0.0193
PM10, lb/MBtu (HHV)	0.0092	0.0092	0.0114	0.0144	0.0101	0.0101	0.0124	0.0155	0.0103	0.0103	0.0126	0.0158	0.0115	0.0115	0.0138	0.0174

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
HRSG Duct Burners																
Duct Burner Fuel																
Duct Burner Heat Input, MBtu/h (LHV)	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	8,167	0	0	0	8,167	0	0	0	8,167	0	0	0	8,167	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	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	23,091	23,091	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	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	2.00	2.00	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	0.080	0.080	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	0.040	0.040	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	0.060	0.060	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	0.004	0.004	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	0.010	0.010	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	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000
DB NOx, lb/h	15.10	0.00	0.00	0.00	15.10	0.00	0.00	0.00	15.10	0.00	0.00	0.00	15.10	0.00	0.00	0.00
DB CO, lb/h	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00
DB UHC (as CH4), lb/h	11.30	0.00	0.00	0.00	11.30	0.00	0.00	0.00	11.30	0.00	0.00	0.00	11.30	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.80	0.00	0.00	0.00	0.80	0.00	0.00	0.00	0.80	0.00	0.00	0.00	0.80	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions																
Stack Exhaust Analysis - Volume Basis - Wet																
Ar	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.93%	0.94%	0.92%	0.93%	0.93%	0.93%	0.92%	0.92%	0.92%	0.92%
CO2	4.07%	3.73%	3.85%	3.77%	4.10%	3.72%	3.77%	3.85%	4.11%	3.72%	3.75%	3.61%	4.09%	3.67%	3.64%	3.43%
H2O	8.04%	7.37%	7.61%	7.46%	8.93%	8.20%	8.29%	8.05%	9.65%	8.90%	8.96%	8.69%	10.50%	9.69%	9.64%	9.24%
N2	74.81%	75.07%	74.98%	75.04%	74.14%	74.43%	74.39%	74.48%	73.59%	73.88%	73.85%	73.96%	72.91%	73.22%	73.24%	73.40%
O2	12.13%	12.88%	12.62%	12.79%	11.90%	12.72%	12.61%	12.88%	11.74%	12.57%	12.51%	12.82%	11.58%	12.50%	12.56%	13.01%
SO2 (after SO2 oxidation)	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000090%	0.000100%	0.000100%	0.000100%	0.000090%	0.000100%	0.000100%	0.000090%	0.000090%
SO3 (after SO2 oxidation)	0.000040%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	194	202	193	185	194	201	191	183	194	202	193	185	190	200	193	189
Stack Diameter, ft (estimated)	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Stack Flow, lb/h	3,972,163	3,963,996	3,108,997	2,521,998	3,620,163	3,611,996	2,909,997	2,406,998	3,538,164	3,529,997	2,868,997	2,380,998	3,215,164	3,206,997	2,699,997	2,269,998
Stack Flow, acfm	882,483	879,347	690,198	559,464	807,297	803,670	647,960	535,558	790,780	787,778	640,265	530,963	721,269	717,834	604,350	507,723
Stack Flow, scfm	1,110,883	1,120,491	868,375	693,870	1,014,853	1,022,798	811,890	662,727	994,815	1,003,108	803,798	659,537	902,390	911,323	759,150	633,708
Stack Exit Velocity, ft/s	73.0	73.0	57.0	45.0	66.0	67.0	53.0	43.0	65.0	66.0	53.0	43.0	59.0	60.0	50.0	42.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)																
NOx, ppmvd (dry, 15% O2)	10.2	9.0	9.0	9.0	10.3	9.0	9.0	9.0	10.3	9.0	9.0	9.0	10.4	9.0	9.0	9.0
NOx, ppmvd (dry)	13.2	10.6	11.0	10.8	13.6	10.7	10.9	10.5	13.7	10.8	10.9	10.4	14.0	10.7	10.7	10.0
NOx, ppmvw (wet)	12.2	9.9	10.2	10.0	12.4	9.8	10.0	9.6	12.4	9.8	9.9	9.5	12.5	9.7	9.6	9.1
NOx, lb/h as NO2 (includes correction adder)	78.1	63.1	51.1	40.6	72.7	57.6	47.0	38.0	71.5	56.4	47.0	37.0	65.8	50.7	43.0	34.0
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0406	0.0359	0.0359	0.0359	0.0410	0.0359	0.0359	0.0363	0.0411	0.0359	0.0365	0.0360	0.0416	0.0359	0.0365	0.0364
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0366	0.0324	0.0324	0.0324	0.0369	0.0324	0.0324	0.0327	0.0370	0.0324	0.0329	0.0325	0.0375	0.0324	0.0329	0.0328
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)																
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	2.6	2.4	2.4	2.4	2.6	2.4	2.4	2.3	2.7	2.4	2.4	2.3	2.7	2.4	2.4	2.2
NOx, ppmvw (wet)	2.4	2.2	2.3	2.2	2.4	2.2	2.2	2.1	2.4	2.2	2.2	2.1	2.4	2.2	2.1	2.0
NOx, lb/h as NO2 (includes NOx margin applied to CTG)	15.4	14.0	11.4	9.0	14.2	12.8	10.4	8.4	13.9	12.5	10.4	8.2	12.6	11.3	9.6	7.6
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0081	0.0080	0.0080	0.0081	0.0080	0.0080	0.0080	0.0081	0.0081
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0073	0.0072	0.0072	0.0073	0.0072	0.0072	0.0072	0.0073	0.0073
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	14.2	13.0	10.5	8.3	13.1	11.8	9.7	7.7	12.9	11.6	9.5	7.6	11.7	10.4	8.7	6.9
Stack CO Emissions																
CO, ppmvd (dry, 15% O2)	7.6	4.1	7.4	7.5	7.6	4.1	7.4	7.7	7.6	4.1	7.4	7.8	7.6	4.1	7.6	8.1
CO, ppmvd (dry)	9.9	4.8	9.0	9.0	10.0	4.9	9.0	9.0	10.1	4.9	9.0	9.0	10.2	4.9	9.0	9.0
CO, ppmvw (wet)	9.1	4.5	8.3	8.3	9.1	4.5	8.3	8.3	9.2	4.5	8.2	8.2	9.1	4.4	8.1	8.2
CO, lb/h (includes CO correction as applied to CTG and margin)	35.5	17.5	25.4	21.0	32.7	16.0	24.0	20.0	32.1	15.6	23.2	19.3	29.2	14.1	22.0	18.4
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0184	0.0100	0.0179	0.0186	0.0184	0.0100	0.0183	0.0191	0.0184	0.0100	0.0181	0.0188	0.0184	0.0100	0.0187	0.0197
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0090	0.0161	0.0167	0.0166	0.0090	0.0165	0.0172	0.0166	0.0090	0.0163	0.0170	0.0166	0.0090	0.0168	0.0177
Stack SO2 Emissions after SO2 Oxidation																
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.81	0.88	0.88	0.88	0.81	0.86	0.88	0.88	0.81	0.88	0.88	0.88	0.82	0.88	0.88	0.88
SO2, ppmvd (dry)	1.06	1.04	1.08	1.06	1.08	1.05	1.07	1.03	1.09	1.06	1.07	1.02	1.10	1.05	1.04	0.98
SO2, ppmvw (wet)	0.97	0.97	1.00	0.98	0.96	0.96	0.98	0.95	0.98	0.96	0.97	0.93	0.98	0.95	0.94	0.89
SO2, lb/h	8.68	8.61	6.98	5.54	8.01	7.86	6.41	5.13	7.86	7.69	6.31	5.03	7.17	6.92	5.78	4.58
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0045	0.0049	0.0049	0.0049	0.0045	0.0049	0.0049	0.0049	0.0045	0.0049	0.0049	0.0049	0.0045	0.0049	0.0049	0.0049
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0041	0.0044	0.0044	0.0044	0.0041	0.0044	0.0044	0.0044	0.0041	0.0044	0.0044	0.0044	0.0041	0.0044	0.0044	0.0044

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions - continued																
Stack UHC Emissions																
UHC, ppmvd (dry, 15% O2)	10.1	6.4	6.2	6.3	10.4	6.4	6.3	6.5	10.5	6.4	6.4	6.6	10.9	6.5	6.5	6.9
UHC, ppmvd	13.1	7.6	7.6	7.6	13.7	7.6	7.6	7.8	14.0	7.7	7.7	7.7	14.7	7.8	7.7	7.7
UHC, ppmvw	12.0	7.0	7.0	7.0	12.5	7.0	7.0	7.0	12.8	7.0	7.0	7.0	13.2	7.0	7.0	7.0
UHC, lb/h as CH4 (includes correction adder)	26.9	15.8	12.3	10.0	25.8	14.3	11.5	9.5	25.3	14.0	11.4	9.4	24.1	12.8	11.0	9.0
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0140	0.0089	0.0086	0.0088	0.0144	0.0089	0.0088	0.0091	0.0145	0.0089	0.0088	0.0092	0.0152	0.0090	0.0093	0.0097
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0126	0.0080	0.0078	0.0080	0.0130	0.0080	0.0079	0.0082	0.0131	0.0080	0.0080	0.0083	0.0137	0.0081	0.0084	0.0087
Stack VOC Emissions																
VOC, ppmvd (dry, 15% O2)	1.4	1.3	1.2	1.3	1.5	1.3	1.3	1.3	1.5	1.3	1.3	1.3	1.5	1.3	1.3	1.4
VOC, ppmvd (dry)	1.9	1.5	1.5	1.5	1.9	1.5	1.5	1.5	2.0	1.5	1.5	1.5	2.0	1.6	1.5	1.5
VOC, ppmvw (wet)	1.7	1.4	1.4	1.4	1.8	1.4	1.4	1.4	1.8	1.4	1.4	1.4	1.8	1.4	1.4	1.4
VOC, lb/h as CH4 (includes correction adder)	3.9	3.1	2.5	2.0	3.6	2.9	2.3	1.9	3.6	2.8	2.3	1.9	3.3	2.6	2.2	1.8
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0020	0.0018	0.0017	0.0018	0.0020	0.0018	0.0018	0.0018	0.0020	0.0018	0.0018	0.0018	0.0021	0.0018	0.0019	0.0019
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0018	0.0016	0.0016	0.0016	0.0018	0.0016	0.0016	0.0016	0.0018	0.0016	0.0016	0.0017	0.0019	0.0016	0.0017	0.0017
PM10 without the Effects of SO2 oxidation																
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	10.9	9.0	9.0	9.0	10.9	9.0	9.0	9.0	10.9	9.0	9.0	9.0	10.9	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0057	0.0051	0.0063	0.0080	0.0061	0.0056	0.0069	0.0086	0.0063	0.0057	0.0070	0.0088	0.0069	0.0064	0.0076	0.0096
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0051	0.0046	0.0057	0.0072	0.0055	0.0051	0.0062	0.0078	0.0056	0.0052	0.0063	0.0079	0.0062	0.0057	0.0069	0.0087
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	22.5	18.0	18.0	18.0	22.5	18.0	18.0	18.0	22.5	18.0	18.0	18.0	22.5	18.0	18.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0117	0.0103	0.0126	0.0159	0.0127	0.0112	0.0138	0.0172	0.0129	0.0115	0.0140	0.0175	0.0142	0.0127	0.0153	0.0193
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0105	0.0092	0.0114	0.0144	0.0115	0.0101	0.0124	0.0155	0.0117	0.0103	0.0126	0.0158	0.0128	0.0115	0.0138	0.0174
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]																
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	18.1	14.1	13.2	12.3	17.5	13.7	12.8	12.1	17.3	13.6	12.8	12.0	16.7	13.1	12.4	11.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0094	0.0080	0.0092	0.0109	0.0099	0.0085	0.0098	0.0115	0.0100	0.0087	0.0099	0.0117	0.0106	0.0093	0.0106	0.0126
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0085	0.0073	0.0083	0.0098	0.0089	0.0077	0.0088	0.0104	0.0090	0.0078	0.0089	0.0105	0.0095	0.0084	0.0095	0.0113
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	29.7	23.1	22.2	21.3	29.1	22.7	21.8	21.1	29.0	22.6	21.8	21.0	28.4	22.1	21.4	20.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0154	0.0132	0.0156	0.0188	0.0164	0.0141	0.0167	0.0201	0.0167	0.0144	0.0169	0.0205	0.0179	0.0157	0.0182	0.0222
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0139	0.0119	0.0140	0.0170	0.0148	0.0128	0.0150	0.0181	0.0150	0.0130	0.0152	0.0184	0.0162	0.0141	0.0164	0.0200
Total Effects of SO2 Oxidation																
Total SO2 to SO3 conversion rate, %vol	28.6%	22.4%	22.4%	22.4%	28.5%	22.4%	22.4%	22.4%	28.5%	22.4%	22.4%	22.4%	28.3%	22.4%	22.4%	22.4%
Total Amount of SO2 converted to SO3, lb/h	3.48	2.48	2.01	1.60	3.19	2.27	1.85	1.48	3.13	2.22	1.82	1.45	2.83	2.00	1.67	1.32
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	7.18	5.12	4.15	3.30	6.58	4.68	3.82	3.05	6.45	4.58	3.75	3.00	5.83	4.12	3.44	2.73
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	5.33	3.80	3.08	2.45	4.88	3.47	2.83	2.27	4.79	3.40	2.79	2.22	4.33	3.06	2.55	2.02

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	105	105	105	105
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Post Combustion Emissions Control Equipment																
Selective Catalytic Reduction (SCR)																
NOx Removed in SCR, %wt	80.3%	77.8%	77.8%	77.8%	80.5%	77.8%	77.8%	77.8%	80.6%	77.8%	77.8%	77.8%	80.6%	77.8%	77.8%	77.8%
NOx removed in SCR, lb/h	62.8	49.0	39.8	31.6	58.5	44.8	36.6	29.6	57.6	43.9	36.6	28.8	53.2	39.4	33.4	26.4
Ammonia Slip, lb/h	14.2	13.0	10.5	8.3	13.1	11.8	9.7	7.7	12.9	11.8	9.5	7.6	11.7	10.4	8.7	6.9

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 calculated from a General Electric GTPE estimate dated 06/25/2008, while the Emissions data is taken from Simple Cycle runs that were provided by GE dated 12/10/2007.
6. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on typical vendor data.
7. The VOC/UHC ratios for NG and Distillate were taken from the GE guarantee used in FMPA TCU1.
8. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
9. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch.
10. Ammonium sulfates created downstream of the SCR are included in front half particulates and front&back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
11. 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.
12. The Duct Burner was assumed to have a maximum duct firing capacity of 170MBTU/h (LHV) which has been applied to all duct firing cases.
13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf and Distillate oil with a maximum Sulfur content of 15 ppm (0.0015%)

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Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG *Fuel Type*	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions																
Ambient Temperature, F	7.0	7.0	7.0	7.0	59.0	59.0	59.0	59.0	68.8	68.8	68.8	68.8	103.0	103.0	103.0	103.0
Ambient Relative Humidity, %	74.0	74.0	74.0	74.0	60.0	60.0	60.0	60.0	73.4	73.4	73.4	73.4	60.0	60.0	60.0	60.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	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	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	7.0	7.0	7.0	7.0	59.0	59.0	59.0	59.0	68.8	68.8	68.8	68.8	103.0	103.0	103.0	103.0
CTG Compr. Inlet Relative Humidity, %	74.2	74.2	74.2	74.2	60.1	60.1	60.1	60.1	73.5	73.5	73.5	73.5	60.1	60.1	60.1	60.1
Inlet Loss, in. H2O	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Exhaust Loss, in. H2O	20.3	20.3	12.3	8.2	17.3	17.3	11.2	7.7	16.6	16.6	10.9	7.5	13.7	13.7	9.6	6.8
CTG Load Level (percent of Base Load)	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
Gross CTG Output, kW	196,378	196,378	147,283	98,189	180,148	180,148	135,111	90,074	174,680	174,680	131,010	87,340	151,346	151,346	113,510	75,673
Gross CTG Heat Rate, Btu/kWh (LHV)	10,047	10,047	10,786	12,659	10,151	10,151	10,969	12,948	10,206	10,206	11,055	13,042	10,524	10,524	11,586	13,603
Gross CTG Heat Rate, Btu/kWh (HHV)	10,700	10,700	11,487	13,482	10,811	10,811	11,682	13,790	10,870	10,870	11,774	13,890	11,208	11,208	12,339	14,488
CTG Heat Input, MBtu/h (LHV)	1,973.0	1,973.0	1,588.6	1,243.0	1,828.7	1,828.7	1,482.0	1,166.3	1,782.8	1,782.8	1,448.3	1,139.1	1,592.8	1,592.8	1,315.1	1,029.4
CTG Heat Input, MBtu/h (HHV)	2,101.3	2,101.3	1,691.9	1,323.8	1,947.5	1,947.5	1,578.4	1,242.1	1,898.7	1,898.7	1,542.5	1,213.2	1,696.3	1,696.3	1,400.7	1,096.3
CTG Water/Steam Injection Flow, lb/h	147,820	147,820	111,160	78,230	136,480	136,480	101,240	71,350	128,480	128,480	95,090	66,330	99,150	99,150	73,200	48,760
Injection Fluid/Fuel Ratio	1.4	1.4	1.3	1.2	1.4	1.4	1.3	1.1	1.3	1.3	1.2	1.1	1.1	1.1	1.0	0.9
CTG Exhaust Flow, lb/h	4,138,000	4,138,000	3,164,000	2,553,000	3,773,000	3,773,000	2,998,000	2,462,000	3,681,000	3,681,000	2,946,000	2,436,000	3,309,000	3,309,000	2,756,000	2,322,000
CTG Exhaust Temperature, F	1,041	1,041	1,126	1,179	1,099	1,099	1,160	1,200	1,111	1,111	1,168	1,200	1,158	1,158	1,199	1,200
Combustion Turbine Fuel																
Total CTG Fuel Flow, lb/h	107,810	107,810	86,810	67,920	99,930	99,930	80,990	63,730	97,420	97,420	79,140	62,250	87,040	87,040	71,860	56,250
CTG Fuel Temperature, F	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
CTG Fuel LHV, Btu/lb	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
CTG Fuel HHV, Btu/lb	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Owner JEA
Plant JEA Greenland Energy Center
Project No. 160167.005
Title Combined Cycle Emissions, Revision 1

Unit
File No.

Computed By VV
Date 07/03/08
Verified By _____
Date _____

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Combined Cycle Emissions, Revision 1

Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Combustion Turbine Exhaust																
CTG Exhaust Analysis (Volume Basis - Wet)																
Ar	0.90%	0.90%	0.90%	0.90%	0.89%	0.89%	0.89%	0.90%	0.88%	0.88%	0.89%	0.90%	0.87%	0.87%	0.87%	0.88%
CO2	5.22%	5.22%	5.50%	5.34%	5.29%	5.29%	5.40%	5.19%	5.27%	5.27%	5.36%	5.11%	5.21%	5.21%	5.17%	4.82%
H2O	11.16%	11.16%	11.36%	10.51%	12.08%	12.08%	11.83%	10.86%	12.53%	12.53%	12.23%	11.21%	14.02%	14.02%	13.48%	12.31%
N2	71.43%	71.43%	71.39%	71.99%	70.75%	70.75%	70.99%	71.64%	70.38%	70.38%	70.66%	71.35%	69.20%	69.20%	69.60%	70.38%
O2	11.29%	11.29%	10.86%	11.25%	11.00%	11.00%	10.89%	11.39%	10.93%	10.93%	10.87%	11.43%	10.70%	10.70%	10.87%	11.61%
SO2, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%
SO3, (after SO2 oxidation)	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%	0.00001%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Wt, lb/mol	28.29	28.29	28.30	28.38	28.20	28.20	28.24	28.32	28.15	28.15	28.19	28.28	27.98	27.98	28.03	28.12
Specific Volume, ft^3/lb	36.90	36.90	39.72	41.34	38.72	38.72	40.77	42.01	39.16	39.16	41.07	42.09	40.85	40.85	42.22	42.39
Specific Volume, scf/lb	13.41	13.41	13.41	13.37	13.45	13.45	13.44	13.40	13.48	13.48	13.46	13.42	13.56	13.56	13.53	13.49
Exhaust Gas Flow, acfm	2,544,870	2,544,870	2,094,568	1,759,017	2,434,843	2,434,843	2,037,141	1,723,810	2,402,466	2,402,466	2,016,537	1,708,854	2,252,878	2,252,878	1,939,305	1,640,493
Exhaust Gas Flow, scfm	924,843	924,843	707,154	568,894	845,781	845,781	671,552	549,847	826,998	826,998	660,886	544,852	747,834	747,834	621,478	522,063
CTG NOx Emissions (Without Post Combustion Emissions Control)																
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.67	0.00
Additional Percent Margin included in mass based NOx Emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
NOx, ppmvd (dry, 15% O2)	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00
NOx, ppmvd (dry)	58.05	58.05	61.29	59.02	59.44	59.44	60.54	57.55	59.59	59.59	60.37	56.94	59.89	59.89	59.11	54.36
NOx, ppmvw (wet)	51.57	51.57	54.33	52.82	52.26	52.26	53.37	51.29	52.12	52.12	52.99	50.56	51.49	51.49	51.14	47.67
NOx, lb/h as NO2	347.1	347.1	279.5	218.7	321.7	321.7	260.7	205.2	313.6	313.6	254.8	200.4	280.2	280.2	233.0	181.1
NOx, lb/MBtu (LHV)	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1772	0.1759
NOx, lb/MBtu (HHV)	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1664	0.1652
CTG CO Emissions (Without Post Combustion Emissions Control)																
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.15	0.00	0.00	0.35	0.44
Additional Percent Margin included in mass based CO Emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd (dry, 15% O2)	7.16	8.00	13.71	14.23	7.09	8.00	13.88	14.59	7.07	8.00	13.91	14.75	6.96	8.00	14.21	15.45
CO, ppmvd (dry)	9.89	11.06	20.00	20.00	10.03	11.32	20.00	20.00	10.03	11.35	20.00	20.00	9.92	11.41	20.00	20.00
CO, ppmvw (wet)	8.79	9.82	17.73	17.90	8.82	9.95	17.63	17.82	8.77	9.93	17.55	17.76	8.53	9.81	17.30	17.54
CO, lb/h	36.0	40.3	55.5	45.1	33.1	37.3	52.4	43.4	32.1	36.4	52.0	43.0	28.3	32.5	48.0	41.0
CO, lb/MBtu (LHV)	0.0183	0.0204	0.0349	0.0363	0.0181	0.0204	0.0354	0.0372	0.0180	0.0204	0.0358	0.0377	0.0177	0.0204	0.0365	0.0398
CO, lb/MBtu (HHV)	0.0171	0.0192	0.0328	0.0341	0.0170	0.0192	0.0332	0.0349	0.0169	0.0192	0.0337	0.0354	0.0167	0.0192	0.0343	0.0374
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)																
SO2 massflow (lb/h) added to match CTG manufacturer's lb/h SO2 emissions estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin included in lb/h SO2 Emissions below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
SO2, ppmvd (dry, 15% O2)	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247	0.2247
SO2, ppmvd (dry)	0.3106	0.3106	0.3279	0.3157	0.3179	0.3179	0.3238	0.3079	0.3188	0.3188	0.3229	0.3046	0.3204	0.3204	0.3162	0.2908
SO2, ppmvw (wet)	0.2759	0.2759	0.2906	0.2826	0.2795	0.2795	0.2855	0.2744	0.2788	0.2788	0.2834	0.2704	0.2755	0.2755	0.2736	0.2550
SO2, lb/h	2.5850	2.5850	2.0815	1.6286	2.3961	2.3961	1.9419	1.5281	2.3359	2.3359	1.8976	1.4926	2.0870	2.0870	1.7230	1.3487
SO2, lb/MBtu (LHV)	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SO2, lb/MBtu (HHV)	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012

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Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Combustion Turbine Exhaust - continued																
CTG UHC Emissions (Without Post Combustion Emissions Control)																
UHC massflow (lb/h) added to match CTG manufacturer's lb/h CO emissions estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.24	0.00	0.00	0.26	0.33	0.00	0.00	0.00	0.00
Additional Percent Margin included in lb/h UHC Emissions Below	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
UHC, ppmvd (dry, 15% O2)	5.7	5.7	5.4	5.6	5.6	5.6	5.5	5.7	5.6	5.6	5.5	5.8	5.7	5.7	5.7	6.2
UHC, ppmvd (dry)	7.9	7.9	7.9	7.8	8.0	8.0	7.9	7.9	8.0	8.0	8.0	7.9	8.1	8.1	8.1	8.0
UHC, ppmvw (wet)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	16.4	16.4	12.6	10.1	15.0	15.0	12.0	10.0	14.7	14.7	12.0	10.0	13.3	13.3	11.0	9.3
UHC, lb/MBtu as CH4 (LHV)	0.0083	0.0083	0.0079	0.0081	0.0082	0.0082	0.0081	0.0086	0.0082	0.0082	0.0083	0.0088	0.0083	0.0083	0.0084	0.0090
UHC, lb/MBtu as CH4 (HHV)	0.0078	0.0078	0.0074	0.0076	0.0077	0.0077	0.0076	0.0081	0.0077	0.0077	0.0078	0.0082	0.0078	0.0078	0.0079	0.0085
CTG VOC Emissions (Without Post Combustion Emissions Control)																
VOC Massflow (lb/h) added to match CTG manufacturer's lb/h VOC emissions estimate	0.00	0.00	3.49	2.98	0.00	0.00	3.62	3.05	0.00	0.00	3.65	3.07	0.00	0.00	3.29	2.65
Additional percent margin included in lb/h VOC emissions below	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.2
VOC, ppmvd (dry)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	3.3	3.3	6.0	5.0	3.0	3.0	6.0	5.0	2.9	2.9	6.0	5.0	2.7	2.7	5.5	4.5
VOC, lb/MBtu as CH4 (LHV)	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016	0.0016	0.0017	0.0016	0.0016	0.0017	0.0018	0.0017	0.0017	0.0017	0.0018
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0016	0.0015	0.0015	0.0015	0.0015	0.0015	0.0016	0.0015	0.0015	0.0016	0.0016	0.0016	0.0016	0.0016	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%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PM10, lb/MBtu (LHV)	0.0086	0.0086	0.0107	0.0137	0.0093	0.0093	0.0115	0.0146	0.0095	0.0095	0.0117	0.0149	0.0107	0.0107	0.0129	0.0165
PM10, lb/MBtu (HHV)	0.0081	0.0081	0.0100	0.0128	0.0087	0.0087	0.0108	0.0137	0.0090	0.0090	0.0110	0.0140	0.0100	0.0100	0.0121	0.0155
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
PM10, lb/MBtu (LHV)	0.0172	0.0172	0.0214	0.0274	0.0186	0.0186	0.0229	0.0292	0.0191	0.0191	0.0235	0.0298	0.0213	0.0213	0.0259	0.0330
PM10, lb/MBtu (HHV)	0.0162	0.0162	0.0201	0.0257	0.0175	0.0175	0.0215	0.0274	0.0179	0.0179	0.0220	0.0280	0.0200	0.0200	0.0243	0.0310

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Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HRSG Duct Burners																
Duct Burner Fuel																
Duct Burner Heat Input, MBtu/h (LHV)	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0	170.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0	188.6	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	8,167	0	0	0	8,167	0	0	0	8,167	0	0	0	8,167	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	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	23,091	23,091	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Duct Burner Emissions																
Duct Burner NOx, lb/MBtu (HHV)	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120	0.120
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	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	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%	10.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000	0.966	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000	0.134	0.000	0.000	0.000
DB NOx, lb/h	22.60	0.00	0.00	0.00	22.60	0.00	0.00	0.00	22.60	0.00	0.00	0.00	22.60	0.00	0.00	0.00
DB CO, lb/h	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00	7.50	0.00	0.00	0.00
DB UHC (as CH4), lb/h	5.70	0.00	0.00	0.00	5.70	0.00	0.00	0.00	5.70	0.00	0.00	0.00	5.70	0.00	0.00	0.00
DB VOC (as CH4), lb/h	2.80	0.00	0.00	0.00	2.80	0.00	0.00	0.00	2.80	0.00	0.00	0.00	2.80	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00	1.90	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00	4.50	0.00	0.00	0.00

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Combined Cycle Emissions, Revision 1

Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Stack Emissions																
Stack Exhaust Analysis - Volume Basis - Wet																
Ar	0.89%	0.90%	0.90%	0.90%	0.89%	0.89%	0.89%	0.90%	0.88%	0.88%	0.89%	0.90%	0.87%	0.87%	0.87%	0.88%
CO2	5.54%	5.22%	5.50%	5.34%	5.64%	5.29%	5.40%	5.19%	5.63%	5.27%	5.36%	5.11%	5.61%	5.21%	5.17%	4.82%
H2O	11.79%	11.16%	11.36%	10.51%	12.76%	12.08%	11.83%	10.88%	13.23%	12.53%	12.23%	11.21%	14.78%	14.02%	13.48%	12.31%
N2	71.19%	71.43%	71.39%	71.99%	70.49%	70.75%	70.99%	71.64%	70.12%	70.38%	70.66%	71.35%	68.92%	69.20%	69.60%	70.38%
O2	10.58%	11.29%	10.86%	11.25%	10.23%	11.00%	10.89%	11.39%	10.13%	10.93%	10.87%	11.43%	9.83%	10.70%	10.87%	11.81%
SO2 (after SO2 oxidation)	0.000030%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000030%	0.000020%
SO3 (after SO2 oxidation)	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	326	326	320	316	324	324	319	315	324	323	319	315	322	321	318	315
Stack Diameter, ft (estimated)	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Stack Flow, lb/h	4,146,168	4,137,999	3,163,999	2,552,999	3,781,166	3,772,999	2,997,999	2,461,999	3,689,166	3,680,999	2,945,999	2,435,999	3,317,166	3,308,999	2,755,999	2,321,999
Stack Flow, scfm	928,050	924,843	707,154	568,894	849,502	845,781	671,552	549,847	830,063	826,998	660,886	544,852	750,785	747,834	621,478	522,063
Stack Flow, acfm	1,404,169	1,399,334	1,060,467	849,298	1,281,185	1,275,903	1,005,829	820,256	1,251,857	1,246,632	989,856	812,812	1,129,495	1,124,509	930,150	776,257
Stack Exit Velocity, ft/s	92.0	92.0	69.0	56.0	84.0	84.0	66.0	54.0	82.0	82.0	65.0	53.0	74.0	74.0	61.0	51.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)																
NOx, ppmvd (dry, 15% O2)	41.3	42.0	42.0	42.0	41.3	42.0	42.0	42.0	41.3	42.0	42.0	42.0	41.2	42.0	42.0	42.0
NOx, ppmvd (dry)	62.1	58.1	61.3	59.0	63.9	59.4	60.5	57.6	64.2	59.6	60.4	56.9	65.0	59.9	59.1	54.4
NOx, ppmvw (wet)	54.8	51.6	54.3	52.8	55.7	52.3	53.4	51.3	55.7	52.1	53.0	50.6	55.4	51.5	51.1	47.7
NOx, lb/h as NO2 (includes correction adder)	369.7	347.1	279.5	218.6	344.3	321.7	260.7	205.2	336.2	313.6	254.8	200.4	302.8	280.2	233.0	181.1
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.1725	0.1759	0.1759	0.1759	0.1723	0.1759	0.1759	0.1759	0.1722	0.1759	0.1759	0.1759	0.1718	0.1759	0.1772	0.1759
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel	0.1614	0.1652	0.1652	0.1652	0.1612	0.1652	0.1652	0.1652	0.1611	0.1652	0.1652	0.1652	0.1607	0.1652	0.1664	0.1652
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)																
NOx, ppmvd (dry, 15% O2)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
NOx, ppmvd (dry)	12.0	11.1	11.7	11.2	12.4	11.3	11.5	11.0	12.4	11.4	11.5	10.8	12.6	11.4	11.3	10.4
NOx, ppmvw (wet)	10.6	9.8	10.3	10.1	10.8	10.0	10.2	9.8	10.8	9.9	10.1	9.6	10.8	9.8	9.7	9.1
NOx, lb/h as NO2 (includes NOx margin applied to CTG)	71.5	66.1	53.2	41.6	66.7	61.3	49.7	39.1	65.2	59.7	48.5	38.2	58.8	53.4	44.4	34.5
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0334	0.0335	0.0335	0.0335	0.0334	0.0335	0.0335	0.0335	0.0334	0.0335	0.0335	0.0335	0.0334	0.0335	0.0337	0.0335
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0312	0.0315	0.0315	0.0315	0.0312	0.0315	0.0315	0.0315	0.0312	0.0315	0.0315	0.0315	0.0312	0.0315	0.0317	0.0315
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	18.6	15.3	12.3	9.6	15.4	14.2	11.5	9.0	15.1	13.8	11.2	8.8	13.6	12.3	10.2	8.0
Stack CO Emissions																
CO, ppmvd (dry, 15% O2)	8.0	8.0	13.7	14.2	8.0	8.0	13.9	14.6	8.0	8.0	13.9	14.8	8.0	8.0	14.2	15.5
CO, ppmvd (dry)	12.0	11.1	20.0	20.0	12.4	11.3	20.0	20.0	12.4	11.4	20.0	20.0	12.6	11.4	20.0	20.0
CO, ppmvw (wet)	10.6	9.8	17.7	17.9	10.8	10.0	17.6	17.8	10.8	9.9	17.6	17.8	10.8	9.8	17.3	17.5
CO, lb/h (includes CO correction as applied to CTG and margin)	43.6	40.2	55.5	45.1	40.6	37.3	52.4	43.4	39.7	36.4	52.0	43.0	35.8	32.5	48.0	41.0
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0203	0.0204	0.0349	0.0363	0.0203	0.0204	0.0354	0.0372	0.0203	0.0204	0.0359	0.0377	0.0203	0.0204	0.0365	0.0398
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0190	0.0192	0.0328	0.0341	0.0190	0.0192	0.0332	0.0349	0.0190	0.0192	0.0337	0.0354	0.0190	0.0192	0.0343	0.0374
Stack SO2 Emissions after SO2 Oxidation																
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.26	0.22	0.22	0.22	0.26	0.22	0.22	0.22	0.26	0.22	0.22	0.22	0.27	0.22	0.22	0.22
SO2, ppmvd (dry)	0.39	0.30	0.32	0.31	0.40	0.31	0.31	0.30	0.41	0.31	0.31	0.30	0.43	0.31	0.31	0.28
SO2, ppmvw (wet)	0.34	0.27	0.28	0.27	0.35	0.27	0.28	0.27	0.35	0.27	0.27	0.26	0.36	0.27	0.27	0.25
SO2, lb/h	3.19	2.51	2.02	1.58	3.03	2.32	1.88	1.48	2.98	2.27	1.84	1.45	2.76	2.02	1.67	1.31
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0015	0.0013	0.0013	0.0013	0.0015	0.0013	0.0013	0.0013	0.0015	0.0013	0.0013	0.0013	0.0016	0.0013	0.0013	0.0013
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0014	0.0012	0.0012	0.0012	0.0014	0.0012	0.0012	0.0012	0.0014	0.0012	0.0012	0.0012	0.0015	0.0012	0.0012	0.0012

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Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Stack Emissions - continued																
Stack UHC Emissions																
UHC, ppmvd (dry, 15% O2)	7.1	5.7	5.4	5.6	7.1	5.6	5.5	5.7	7.2	5.6	5.5	5.8	7.4	5.7	5.7	6.2
UHC, ppmvd	10.6	7.9	7.9	7.8	11.0	8.0	7.9	7.9	11.1	8.0	8.0	7.9	11.7	8.1	8.1	8.0
UHC, ppmvw	9.4	7.0	7.0	7.0	9.6	7.0	7.0	7.0	9.7	7.0	7.0	7.0	9.9	7.0	7.0	7.0
UHC, lb/h as CH4 (includes correction adder)	22.1	16.4	12.6	10.1	20.7	15.0	12.0	10.0	20.3	14.7	12.0	10.0	18.9	13.3	11.0	9.3
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0103	0.0083	0.0079	0.0081	0.0103	0.0082	0.0081	0.0086	0.0104	0.0082	0.0083	0.0088	0.0107	0.0083	0.0084	0.0090
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0096	0.0078	0.0074	0.0076	0.0097	0.0077	0.0076	0.0081	0.0097	0.0077	0.0078	0.0082	0.0100	0.0078	0.0079	0.0085
Stack VOC Emissions																
VOC, ppmvd (dry, 15% O2)	2.0	1.1	1.1	1.1	2.0	1.1	1.1	1.1	2.0	1.1	1.1	1.2	2.1	1.1	1.1	1.2
VOC, ppmvd (dry)	2.9	1.6	1.6	1.6	3.1	1.6	1.6	1.6	3.2	1.6	1.6	1.6	3.4	1.6	1.6	1.6
VOC, ppmvw (wet)	2.6	1.4	1.4	1.4	2.7	1.4	1.4	1.4	2.7	1.4	1.4	1.4	2.9	1.4	1.4	1.4
VOC, lb/h as CH4 (includes correction adder)	6.1	3.3	6.0	5.0	5.8	3.0	6.0	5.0	5.8	2.9	6.0	5.0	5.5	2.7	5.5	4.5
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0029	0.0017	0.0038	0.0040	0.0029	0.0016	0.0040	0.0043	0.0030	0.0016	0.0041	0.0044	0.0031	0.0017	0.0042	0.0044
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0027	0.0016	0.0035	0.0038	0.0027	0.0015	0.0038	0.0040	0.0028	0.0015	0.0039	0.0041	0.0029	0.0016	0.0039	0.0041
PM10 without the Effects of SO2 oxidation																
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	18.9	17.0	17.0	17.0	18.9	17.0	17.0	17.0	18.9	17.0	17.0	17.0	18.9	17.0	17.0	17.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0088	0.0086	0.0107	0.0137	0.0094	0.0093	0.0115	0.0146	0.0097	0.0095	0.0117	0.0149	0.0107	0.0107	0.0129	0.0165
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0082	0.0081	0.0100	0.0128	0.0088	0.0087	0.0108	0.0137	0.0090	0.0090	0.0110	0.0140	0.0100	0.0100	0.0121	0.0155
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	38.5	34.0	34.0	34.0	38.5	34.0	34.0	34.0	38.5	34.0	34.0	34.0	38.5	34.0	34.0	34.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0180	0.0172	0.0214	0.0274	0.0193	0.0186	0.0229	0.0292	0.0197	0.0191	0.0235	0.0298	0.0219	0.0213	0.0259	0.0330
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0168	0.0162	0.0201	0.0257	0.0180	0.0175	0.0215	0.0274	0.0185	0.0179	0.0220	0.0280	0.0204	0.0200	0.0243	0.0310
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]																
PM10 Emissions - Front Half Catch Only																
PM10, lb/h	21.2	18.5	18.2	17.9	21.0	18.4	18.1	17.9	21.0	18.3	18.1	17.9	20.8	18.2	18.0	17.8
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0099	0.0094	0.0115	0.0144	0.0105	0.0101	0.0122	0.0153	0.0107	0.0103	0.0125	0.0157	0.0118	0.0114	0.0137	0.0173
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0092	0.0088	0.0108	0.0136	0.0098	0.0094	0.0115	0.0144	0.0101	0.0097	0.0117	0.0147	0.0110	0.0107	0.0128	0.0162
PM10 Emissions - Front and Back Half Catch																
PM10, lb/h	40.8	35.5	35.2	34.9	40.7	35.4	35.1	34.9	40.6	35.3	35.1	34.9	40.4	35.2	35.0	34.8
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0190	0.0180	0.0222	0.0281	0.0203	0.0193	0.0237	0.0299	0.0208	0.0198	0.0242	0.0306	0.0229	0.0221	0.0266	0.0338
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0178	0.0169	0.0208	0.0264	0.0190	0.0182	0.0223	0.0281	0.0195	0.0186	0.0228	0.0287	0.0214	0.0208	0.0250	0.0317
Total Effects of SO2 Oxidation																
Total SO2 to SO3 conversion rate, %vol	25.8%	22.4%	22.4%	22.4%	25.6%	22.4%	22.4%	22.4%	25.5%	22.4%	22.4%	22.4%	25.1%	22.4%	22.4%	22.4%
Total Amount of SO2 converted to SO3, lb/h	1.11	0.72	0.58	0.46	1.04	0.67	0.54	0.43	1.02	0.65	0.53	0.42	0.92	0.58	0.48	0.38
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	2.29	1.49	1.20	0.94	2.14	1.38	1.12	0.88	2.10	1.35	1.10	0.86	1.90	1.21	1.00	0.78
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	1.70	1.11	0.89	0.70	1.59	1.03	0.83	0.66	1.56	1.00	0.81	0.64	1.41	0.89	0.74	0.58

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Combined Cycle Emissions, Revision 1

Case Number	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	7	59	59	59	59	68.8	68.8	68.8	68.8	103	103	103	103
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Post Combustion Emissions Control Equipment																
Selective Catalytic Reduction (SCR)																
NOx Removed in SCR, %wt	80.7%	81.0%	81.0%	81.0%	80.6%	81.0%	81.0%	81.0%	80.6%	81.0%	81.0%	81.0%	80.6%	81.0%	81.0%	81.0%
NOx removed in SCR, lb/h	298.2	281.0	226.2	177.0	277.6	260.4	211.1	166.1	271.1	253.9	206.2	162.2	244.0	226.8	188.6	146.6
Ammonia Slip, lb/h	16.6	15.3	12.3	9.6	15.4	14.2	11.5	9.0	15.1	13.8	11.2	8.8	13.6	12.3	10.2	8.0

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% 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 calculated from a General Electric GTPE estimate dated 06/25/2008, while the Emissions data is taken from Simple Cycle runs that were provided by GE dated 12/10/2007.
6. Duct burner emissions are included. The duct burner pollutant emissions are Black & Veatch estimates based on typical vendor data.
7. The VOC/UHC ratios for NG and Distillate were taken from the GE guarantee used in FMPA TCU1.
8. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
9. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch.
10. Ammonium sulfates created downstream of the SCR are included in front half particulates and front&back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
11. 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.
12. The Duct Burner was assumed to have a maximum duct firing capacity of 170MBTU/h (LHV) which has been applied to all duct firing cases.
13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf and Distillate oil with a maximum Sulfur content of 15 ppm (0.0015%)

Appendix C
Emission Calculations

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Summary of Potential to Emit for Criteria Pollutants (Simple Cycle and Combined Cycle Configurations)

(Tons per year)

Table C-1

	CO	NO_x	PM/PM_{10}	SO_2	VOC	H_2SO_4	Pb	Hg	Fluorides	H_2S	Total Reduced Sulfur
Simple Cycle Operational Mode PTE[1]											
Units 1 and 2 SCCTs	67.70	340.20	71.00	28.81	10.85	11.03	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Engine Generator	0.45	3.33	0.02	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.07	0.57	0.03	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Heater	2.01	2.41	0.19	0.02	1.27	0.02	0.00	0.00	0.00	0.00	0.00
2 ULSFO Tanks					0.71						
TOTAL (SCCT Operations)	70.24	346.51	71.25	28.82	13.00	11.05	0.00	0.00	0.00	0.00	0.00
Combined Cycle Operational Mode PTE[2]											
Units 1 and 2 CCCTs	290.40	150.64	260.72	70.17	32.64	42.75	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Engine Generator	0.45	3.33	0.02	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.07	0.57	0.03	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Heater	2.01	2.41	0.19	0.02	1.27	0.02	0.00	0.00	0.00	0.00	0.00
Cooling Tower			4.26								
2 ULSFO Tanks					0.50						
TOTAL (CCCT Operations)	292.95	156.95	265.22	70.19	34.57	42.78	0.00	0.00	0.00	0.00	0.00
Worst Case Project PTE[3]	292.95	447.45	265.22	70.96	34.57	42.78					
PSD SER	100	40	25/15	40	40	7	0.6	--	3	10	10
PSD Review Required Based on CCCT Emissions?	YES	YES	YES	YES	NO	YES	NO	--	NO	NO	NO

Notes [ ]:

[1] PTE (SCCT operational Mode) is the expected emissions from combustion turbine operation at 3,500 hours per CTG per year on natural gas alone or the combination of natural gas/ULSFO (3,000 hours per CTG per year on natural gas and 500 hours per CTG per year on ULSFO); whichever is greater. This operational scenario occurs post-construction of the natural gas pipeline and results in a PTE greater than the PTE from firing ULSFO 1,000 hours per year per CTG prior to the natural gas pipeline construction. Also included are potential emissions from the emergency ancillary equipment and the ULSFO storage tanks.

[2] PTE (CCCT operational mode) is the higher of the expected emissions from combustion turbine/duct burner operation at 8,760 hours per CTG/HRSG per year on natural gas alone, OR, the combination of natural gas/ULSFO 8,260 hours per CTG/HRSG per year on natural gas and 500 hours per CTG per year on ULSFO and ductburners on gas). Also included are the emissions from the emergency ancillary equipment (no change from the SCCT operational mode), the ULSFO storage tanks and the cooling tower.

[3] Worst Case Project PTE for emissions of CO, PM/PM10 and VOCs occur when each CCCT operates 8,260 hours/year on natural gas and 500 hours/year on ULSFO. Worst Case Project PTE for emissions of SO_2 occurs when each SCCT operates 3500 hours per year on natural gas and each CCCT operates 5,260 hours per year on natural gas. Worst Case Project PTE for emissions of H_2SO_4 occurs when each CCCT operates 8,760 hours/year on natural gas. Worst Case Project PTE for emissions of NO_x occur when each SCCT operates 3,000 hours/year on natural gas and 500 hours/year on ULSFO, and each CCCT operates 4,760 hours per year on natural gas and 500 hours/year on ULSFO, respectively. Project PTE includes emissions from emergency ancillary equipment. The emergency ancillary equipment will retain the same operational limits as proposed in the SCCT air permit application package (refer to DEP File No. 0310561-001-AC- (PSD-FL-401)).

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Units 1 and 2 SCCT Parameters
Pre- Onsite Natural Gas Availability
Emissions Calculation

Basis:

Unit Type	GE 7FA
Number of Turbines	2
Fuel	ULSFO
Fuel Burn Rate	1,984.1 MBtu/hr [1]
Hours of Operations	1,000 hr/yr per unit

Table C-2a: Units 1 and 2 ULSFO SCCT Emissions

Pollutant	ULSFO		
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)
CO	0.0192 [1]	38.2	38.2
NO_x	0.1652 [1]	329.4	329.4
PM_{10}	0.0171 [1]	34.0	34.0
SO_2	0.0012 [1]	2.5	2.5
VOC	0.0022 [1]	4.3	4.3
H_2SO_4	0.0005 [1]	0.9	0.9
Lead	0.000014 [2]	0.0	0.0
Mercury	0 [3]	0	0.0
Fluorides	0 [3]	0	0.0
H_2S	0 [3,4]	0	0.0
Total Reduced Sulfur	0 [3,4]	0	0.0
CO_2	157 [4,5]	313,074	313,074

Notes [ ]:
1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity) as contained in Appendix B.
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
3. Emissions are insignificant and assumed to be zero.
4. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
5. CO_2 emissions are being listed for informational purposes only.

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Units 1 and 2 CCCT Parameters
Combined Cycle Facility - Pre-Onsite Gas Availability
Estimated Emissions Calculation

Basis:

Unit Type	GE 7FA
Number of Turbines	2
Fuel	ULSFO
CTG Fuel Burn Rate	1,948.0 MBtu/hr [1]
Duct Burner Fuel Burn Rate	0 MBtu/hr [1]
Hours of Operations	500 hr/yr/unit

Table C-2b: Units 1 and 2 CCCT Emissions on ULSFO

Pollutant	ULSFO	
	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)
CO	37.3 [1]	18.65
NO_x	61.3 [1]	30.65
PM_{10}	35.4 [1]	17.70
SO_2	2.3 [1]	1.16
VOC	3.0 [1]	1.50
H_2SO_4	1.0 [1]	0.52
Lead	0 [3]	0.00
Mercury	0 [3]	0.00
Fluorides	0 [3]	0.00
H_2S	0 [3]	0.00
Total Reduced Sulfur	0 [3]	0.00
CO_2	305,836 [2]	152,918

Notes [ ]:
1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity). Duct Burners fire only natural gas, therefore for the pre-onsite natural gas scenario, duct burners can not be used.
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
3. Emissions are insignificant and assumed to be zero.

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Units 1 and 2 SCCT Parameters

Post-Onsite Natural Gas Availability

Emissions Calculation

Basis:

Unit Type	GE 7FA		Unit Type	GE 7FA
Number of Turbines	2		Number of Turbines	2
Fuel	Natural Gas		Fuel	ULSFO
Fuel Burn Rate	1,805.7 MBtu/hr [1]		Fuel Burn Rate	1,994.1 MBtu/hr [1]
Hours of Operations	3,000 hr/yr per unit	Scenario 1 →	Hours of Operations	500 hr/yr per unit
Hours of Operations	3,500 hr/yr per unit	Scenario 2 →	Hours of Operations	0 hr/yr per unit

Table C-3: Units 1 and 2 Natural Gas SCCT Emissions

Pollutant	Natural Gas				ULSFO			PTE Total (tpy)[2]
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr/unit)	Potential to Emit for 3,000 hours (tpy)	Potential to Emit for 3,500 hours (tpy)	Emission Factor (lb/MBtu)	Mass Emission (lb/hr/unit)	Potential to Emit on 500 hours (tpy)	
CO	0.0090 [1]	16.2	48.6	56.7	0.0192 [1]	38.2	19.1	67.7
NO_x	0.0324 [1]	58.5	175.5	204.8	0.1652 [1]	329.4	164.7	340.2
PM_{10}	0.0100 [1]	18.0	54.0	63.0	0.0171 [1]	34.0	17.0	71.0
SO_2	0.0046 [1]	8.2	24.7	28.8	0.0012 [1]	2.5	1.2	28.8
VOC	0.0016 [1]	2.9	8.7	10.2	0.0022 [1]	4.3	2.2	10.9
H_2SO_4	0.0017 [1]	3.2	9.5	11.0	0.0005 [1]	0.9	0.5	11.0
Lead	No Data [3]	0	0.0	0.0	0.000014 [3]	0.0	0.0	0.0
Mercury	0 [4]	0	0.0	0.0	0 [4]	0	0.0	0.0
Fluorides	0 [4]	0	0.0	0.0	0 [4]	0	0.0	0.0
H_2S	0 [4, 5]	0	0.0	0.0	0 [4, 5]	0	0.0	0.0
Total Reduced Sulfur	0 [4, 5]	0	0.0	0.0	0 [4, 5]	0	0.0	0.0
CO_2	110 [3,6]	198,627	595,881	695,195	157 [3,6]	313,074	156,537	752,418

Notes [ ]:

1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity) as contained in Appendix B.
2. PTE Total based on the higher of firing either 3,500 hours per year on natural gas or 3,000 hours per year on natural gas with 500 hours per year on ULSFO.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
6. CO_2 emissions are being listed for informational purposes only.

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Units 1 and 2 CCCT Parameters
Combined Cycle Facility
Estimated Emissions Calculation: Full Year Combined Cycle Operations

Basis:

Unit Type	GE 7FA		
Number of Turbines	2		
Fuel	Natural Gas		ULSFO
CTG Fuel Burn Rate	1,778.0 MBtu/hr [1]		1,948.0 MBtu/hr [1]
Duct Burner Fuel Burn Rate	189 MBtu/hr [1]		189 MBtu/hr [1]
Hours of Operations	8,260 hr/yr/unit	← Scenario 1 →	500 hr/yr/unit
Hours of Operations	8,760 hr/yr/unit	← Scenario 2 →	0 hr/yr/unit

Table C-4a: Units 1 and 2 Natural Gas CCCT Emissions

Pollutant	Natural Gas		ULSFO		PTE Total (tpy)[2,6]
	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	
CO	32.7 [1]	270.10	40.6 [1]	20.30	290.40
NO_x	14.2 [1]	117.29	66.7 [1]	33.35	150.64
PM_{10}	29.1 [1]	240.37	40.7 [1]	20.35	260.72
SO_2	8.0 [1, 6]	70.17	3.0 [1]		70.17
VOC	3.6 [1]	29.74	5.8 [1]	2.90	32.64
H_2SO_4	4.9 [1, 6]	42.75	1.6 [1]		42.75
Lead	0 [3]	0.0	0 [3]	0.0	0.00
Mercury	0 [4]	0.0	0 [4]	0.0	0.00
Fluorides	0 [4]	0.0	0 [4]	0.0	0.00
H_2S	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00
Total Reduced Sulfur	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00
CO_2	217,816 [7]	1,799,159	328,072 [3,7]	164,036	1,963,195

Notes [ ]:

1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity). Includes emissions from Duct Burner firing natural gas.
2. PTE Total based on the higher of firing either 8,760 hours per year on natural gas or 8,260 hours per year on natural gas with 500 hours per year on ULSFO.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SC_2 or H_2SO_4.
6. Worst case SO_2 and H_2SO_4 PTE occur when natural gas is combusted 8,760 hours per year
7. CO_2 emissions are being listed for informational purposes only. CO_2 emissins ae from the CTG and natural gas firing in the duct burners.

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Units 1 and 2 CCCT Parameters

Combined Cycle Facility

Estimated Emissions Calculation: Part-Year Combined Cycle Operations

Basis:

Unit Type	GE 7FA		
Number of Turbines	2		
Fuel	Natural Gas		ULSFO
CTG Fuel Burn Rate	1,778.0 MBtu/hr [1]		1,948.0 MBtu/hr [1]
Duct Burner Fuel Burn Rate	189 MBtu/hr [1]		189 MBtu/hr [1]
Hours of Operations	4,760 hr/yr/unit	Scenario 1	500 hr/yr/unit
Hours of Operations	5,260 hr/yr/unit	Scenario 2	0 hr/yr/unit

Table C-4b: Units 1 and 2 Natural Gas CCCT Emissions

Pollutant	Natural Gas		ULSFO		PTE Total (tpy)[2,6]
	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	
CO	32.7 [1]	155.65	40.6 [1]	20.30	175.95
NO_x	14.2 [1]	67.59	66.7 [1]	33.35	100.94
PM_{10}	29.1 [1]	138.52	40.7 [1]	20.35	158.87
SO_2	8.0 [1, 6]	42.13	3.0 [1]		42.13
VOC	3.6 [1]	17.14	5.8 [1]	2.90	20.04
H_2SO_4	4.9 [1, 6]	25.67	1.6 [1]		25.67
Lead	0 [3]	0.0	0 [3]	0.0	0.00
Mercury	0 [4]	0.0	0 [4]	0.0	0.00
Fluorides	0 [4]	0.0	0 [4]	0.0	0.00
H_2S	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00
Total Reduced Sulfur	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00
CO_2	217,816 [7]	1,036,803	328,072 [3,7]	164,036	1,200,839

Notes [ ]:

1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity). Includes emissions from Duct Burner firing natural gas.
2. PTE Total based on the higher of firing either 5,260 hours per year on natural gas or 4,760 hours per year on natural gas with 500 hours per year on ULSFO.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
6. For this scenario, worst case SO_2 and H_2SO_4 PTE occur when natural gas is combusted 5,260 hours per year
7. CO_2 emissions are being listed for informational purposes only. CO_2 emissins ae from the CTG and natural gas firing in the duct burners.

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Emergency Diesel Engine Generator Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	2,206 HP[1]	
Heat Input	14.70 MBtu/hr	
Heating Value	140,000 Btu/gal[2]	
Fuel Burn Rate	105 gal/hr[1]	24,150 gal/yr
Hours of Operation	230 hrs/yr	

Stack Exit Conditions [1]:

Exhaust Flow Rate	11,071 acfm		
Exhaust Exit Velocity	528.60 ft/sec	161.12 m/sec	
Exhaust Temperature	762.8 °F	679.15 K	
Stack Diameter	8 in	0.67 ft	0.2032 m
Stack Height	24 ft	7.32 m	

Table C-5: Emergency Diesel Engine Generator Emissions

Pollutant	Emission Rate			Potential to Emit (total)
	g/sec	lb/hr		ton/yr
CO	0.4977	3.9500	[1]	4.54E-01
NO_x	3.6514	28.9800	[1]	3.33E+00
PM/PM_{10}	0.0252	0.2000	[1]	2.30E-02
SO_2	0.0028	0.0222	[3]	2.55E-03
VOC	0.0895	0.7100	[1]	8.17E-02
H_2SO_4	0.0043	0.0340	[4]	3.91E-03
Lead	0	0	[5]	0.00E+00
Mercury	0	0	[5]	0.00E+00
Fluorides	0	0	[5]	0.00E+00
H_2S	0	0	[5]	0.00E+00
Total Reduced Sulfur	0	0	[5]	0.00E+00

Operating Scenarios:

24-hr per day operation for short-term emissions

Annual hours of operation given above used for annualizing emissions

Table C-6: Emergency Diesel Engine Generator Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	4.977E-01	3.950E+00	–	–	4.977E-01	3.950E+00	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	9.587E-02	7.609E-01
PM/PM_{10}	–	–	–	–	–	–	2.520E-02	2.000E-01	6.616E-04	5.251E-03
SO_2	–	–	2.795E-03	2.218E-02	–	–	2.795E-03	2.218E-02	7.339E-05	5.825E-04

Notes [ ]:

1. Vendor data - Caterpillar Model 3512 CDITA included in Appendix B of the Simple Cycle Application April 2008.
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

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Emergency Diesel Fire Pump Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	350 BHP[1]	
Heat Input	2.38 MBtu/hr	
Heating Value	140,000 Btu/gal[2]	
Fuel Burn Rate	17.0 gal/hr[1]	6,800 gal/yr
Hours of Operation	400 hrs/yr	

Stack Exit Conditions [1]:

Exhaust Flow Rate	2,345 acfm		
Exhaust Exit Velocity	286.63 ft/sec	87.37 m/sec	
Exhaust Temperature	806 °F	703.15 K	
Stack Diameter	5 in	0.42 ft	0.13 m
Stack Height	15.17 ft	4.62 m	

Table C-7: Emergency Diesel Fire Pump Emissions

Pollutant	Outlet Conditions	Emission Rate			Potential to Emit
	g/bhp-hr	g/sec	lb/hr		ton/yr
CO	0.48	0.0467	0.3704	[1]	7.41E-02
NO_x	3.67	0.3568	2.8318	[1]	5.66E-01
PM/PM_{10}	0.21	0.0204	0.1620	[1]	3.24E-02
SO_2	4.65E-03	0.0005	0.0036	[3]	7.18E-04
VOC	0.52	0.0506	0.4012	[1]	8.02E-02
H_2SO_4	0.01	0.0007	0.0055	[4]	1.10E-03
Lead	0	0	0	[5]	0.00E+00
Mercury	0	0	0	[5]	0.00E+00
Fluorides	0	0	0	[5]	0.00E+00
H_2S	0	0	0	[5]	0.00E+00
Total Reduced Sulfur	0	0	0	[5]	0.00E+00

Operating Scenarios:

24-hr per day operation for short-term emissions

Annual hours of operation given above used for annualizing emissions

Table C-8: Emergency Diesel Fire Pump Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	4.667E-02	3.704E-01	–	–	4.667E-02	3.704E-01	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	1.629E-02	1.293E-01
PM/PM_{10}	–	–	–	–	–	–	2.042E-02	1.620E-01	9.323E-04	7.399E-03
SO_2	–	–	4.526E-04	3.592E-03	–	–	4.526E-04	3.592E-03	2.066E-05	1.640E-04

Notes [ ]:

1. Vendor data - Aurora Model 491 (2,350 RPM), included in Appendix B of the Simple Cycle Application Apirl 2008.
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

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Fuel Gas Heater

Emissions Calculation and Stack Parameters Information

Basis:

Heat Input	5.84	MBtu/hr[1]
Heating Value	1,020	Btu/scf[2]
Fuel Burn Rate	0.0057	mmscf/hr[1]
Hours of Operation	8,760	hrs/yr

Stack Exit Conditions [1]:

Exhaust Flow Rate	1,374	acfm		
Exhaust Exit Velocity	7.29	ft/sec	2.22	m/sec
Exhaust Temperature	1,165	°F	902.59	K
Stack Diameter	24	in	2.00 ft	0.61 m
Stack Height	20	ft	6.10	m

Table C-9: Fuel Gas Heater Emissions

Pollutant	AP-42 EF lb/mmscf	Emission Rate			Potential to Emit
		g/sec	lb/hr		ton/yr
CO		0.0580	0.4600	[1]	2.01E+00
NO_x		0.0693	0.5500	[1]	2.41E+00
PM/PM_{10}	7.60	0.0055	0.0435	[3]	1.90E-01
SO_2	6.00E-01	0.0004	0.0034	[3]	1.50E-02
VOC		0.0365	0.2900	[1]	1.27E+00
H_2SO_4		0.0007	0.0053	[4]	2.30E-02
Lead		0	0	[5]	0.00E+00
Mercury		0	0	[5]	0.00E+00
Fluorides		0	0	[5]	0.00E+00
H_2S		0	0	[5]	0.00E+00
Total Reduced Sulfur		0	0	[5]	0.00E+00

Operating Scenarios:

24-hr per day operation for short-term emissions

Annual hours of operation given above used for annual emissions

Table C-10: Fuel Gas Heater Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	5.796E-02	4.600E-01	–	–	5.796E-02	4.600E-01	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	6.930E-02	5.500E-01
PM/PM_{10}	–	–	–	–	–	–	5.480E-03	4.349E-02	5.480E-03	4.349E-02
SO_2	–	–	4.326E-04	3.434E-03	–	–	4.326E-04	3.434E-03	4.326E-04	3.434E-03

Notes [ ]:

1. Vendor data - NATCO Indirect Fired Water Bath Heater, included in Appendix B of the Simple Cycle Application April 2008.
2. Assumed natural gas heating value of 1,020 Btu/scf. USEPA, AP-42, Fifth Edition, Vol. I. Section 3.1 "Stationary Gas Turbines". April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines."
3. USEPA AP-42 Table 1.4-2
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

JEA (COMBINED CYCLE)

Greenland Energy Center Units 1 and 2

Cooling Tower - Linear Mechanical Draft

Cooling Tower Emissions

Basis (per Tower):

Total Dissolved Solids	718.75	mg/L	
Cycles of Concentration	4	No.	
Cycled Water TDS	2,875	ppmw	
Drift Rate	0.0005	%	
Cell Diameter	28	ft	
Stack Height	51.84	ft	
Circulating Water Flow	135,300	gpm	
Exhaust Air Flow (per cell)	1,225,000	cfm	5,338.20 kg/s
Number of Cells (per tower)	8	No.	
Number of Towers	1	No.	
Heat Dissipation Rate	1775	mMBtu/hr	
Ambient Pressure	14.70	psia	
Relative Humidity	60	%	
Wet Bulb Temperature	69	°F	
Enthalpy of air $_{in}$ (H_{in})	33.08	Btu/lb	
PM_{10}/TSP Fraction	1.000	dimensionless	[1]
$PM_{2.5}$/PM_{10} Fraction	0.600	dimensionless	[2a]

Calculations:

TSP Emission (lb/hr) = Circulating Water Flow Rate (gpm) x (Drift Rate(%)/100) x Density of Circulating Water (lb/gal) x TDS (ppmw) x 60 min/h

TSP Emission (tpy) = TSP Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

PM_{10} Emission (lb/hr) = TSP Emission (lb/hr) x PM_{10}/TSP Frection

PM_{10} Emission (tpy) = PM_{10} Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

$PM_{2.5}$ Emission (lb/hr) = PM_{10} Emission (lb/hr) x $PM_{2.5}$/PM_{10} Fraction

$PM_{2.5}$ Emission (tpy) = $PM_{2.5}$ Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

Table C11 Cooling Tower Emissions

Activity	Number of Towers	Hours of Operation	Circulating Water Flow	Drift Rate	Density Circ Water	TDS	Potential Uncontrolled Emissions tpy			Control Method	Control Efficiency	Potential Controlled Emissions tpy		
	No.	hr/yr	gpm	%	lb/gal	ppmw	TSP	PM10	PM2.5		%	TSP	PM10	PM2.5
Cooling Tower - Mechanical Draft	1	8,760	135,300	0.0005	8.34	2,875	4.26	4.26	2.56	NA	0	4.26	4.26	2.56

Calculations (for modeling):

Exit Velocity (per cell)	33.16	ft/sec	=	10.11	m/sec
Enthalpy of air $_{out}$ (H_{out})	74.98	Btu/lb			
Exit Temperature (dry bulb)	101.92	°F	=	38.84 °C =	311.99 °K

Table C12 Cooling Tower Modeling Parameters

EU Number	Activity	Cells per Tower	Controlled Emissions (per cell) lb/hr			Controlled Emissions (per cell) g/sec		
		No.	TSP	PM10	PM2.5	TSP	PM10	PM2.5
	Cooling Tower - Mechanical Draft	8	0.1217	0.1217	0.0730	0.0153	0.0153	0.0092

Notes [ ]:

1. Assumed all particulate emissions are less than 10 microns.
2. South Coast AQMD, Air Guidance Book "Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds". Final. October 2006.
   a. Table A "Updated CEIDARS Table with PM2.5 Fractions".

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ULSFO Storage Tanks

Table C-13a: VOC Emissions from ULSFO Storage Tanks-Simple Cycle Operations

CTG ULSFO Usage Rate at ISO Conditions			102,310	lb/hr
Operational Hours per CTG per year			1000	hrs
Worst Case ULSFO use per Year for 2 CTGs			204,620,000	lbs/yr
ULSFO Density			6.79	lb/gal

Annual Throughput of ULSFO	3.01E+07	gallons
Annual Throughput per tank	1.51E+07	gallons
From TANKS	**713.65**	**lbs/yr/tank**

Note: Worst case emissions occur during the pre-onsite natural gas pipeline scenario

Table C-13b: VOC Emissions from ULSFO Storage Tanks-Combined Cycle Operations

CTG ULSFO Usage Rate at ISO Conditions			99,930	lb/hr
Operational Hours per CTG per year			500	hrs
Worst Case ULSFO use per Year for 2 CTGs			99,930,000	lbs/yr
ULSFO Density			6.79	lb/gal

Annual Throughput of ULSFO	1.47E+07	gallons
Annual Throughput per tank	7.36E+06	gallons
From TANKS	**498.27**	**lbs/yr/tank**

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Pre- Onsite Natural Gas Availability Simple Cycle and Combined Cycle Operations

Table C-14: Emissions Calculations with CTGs Firing Natural Gas and ULSFO

INPUTS

No. of CTGs
2

Heat Input (MBtu/hr)						
SCCT (GAS) [1]	SCCT (ULSFO) [1]	CCCT (GAS) [1]	CCCT (ULSFO) [1]	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	1778.3	1947.5	2.38	14.70	5.837

Hours of Operation per Unit						
SCCT CTG (GAS)	SCCT CTG (ULSFO)	CCCT CTG (GAS)	CCCT CTG (ULSFO)	Fire Pump	Emergency Engine	Fuel Heater
0	1000	0	500	400	230	0

	SCCT Combustion Turbines			CCCT Combustion Turbines (No Duct Burner)			SCCT + CCCT	Fire Pump			Emergency Diesel Engine Generator			Fuel Heater			
Pollutant	CTG (ULSFO) Emission factor [2] lb/MBtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSFO PTE (tpy)	CTG (ULSFO) Emission factor [2] lb/MBtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSF0 PTE (tpy)	2 CTGs Total ULSFO PTE (tpy)	Fire Pump E.F.[3] lb/MBtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[4] lb/MBtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[5] lb/MBtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Total [6] Project PTE tpy
1,3-Butadiene	1.60E-05	6.38E-02	3.19E-02	1.60E-05	6.38E-02	1.60E-02	4.79E-02	3.91E-05	9.31E-05	1.86E-05							4.79E-02
Acetaldehyde								7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05				4.08E-04
Acrolein								9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05				5.74E-05
Arsenic	1.10E-05	4.39E-02	2.19E-02	1.10E-05	4.39E-02	1.10E-02	3.29E-02										3.29E-02
Benzene	5.50E-05	2.19E-01	1.10E-01	5.50E-05	2.19E-01	5.48E-02	1.65E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	0.00E+00	1.66E-01
Beryllium	3.10E-07	1.24E-03	6.18E-04	3.10E-07	1.24E-03	3.09E-04	9.27E-04										9.27E-04
Cadmium	4.80E-06	1.91E-02	9.57E-03	4.80E-06	1.91E-02	4.79E-03	1.44E-02										1.44E-02
Chromium	1.10E-05	4.39E-02	2.19E-02	1.10E-05	4.39E-02	1.10E-02	3.29E-02										3.29E-02
Chromium (VI)																	0.00E+00
Dichlorobenzene														1.18E-06	6.87E-06	0.00E+00	0.00E+00
Ethylbenzene																	0.00E+00
Formaldehyde	2.80E-04	1.12E+00	5.58E-01	2.80E-04	1.12E+00	2.79E-01	8.38E-01	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.36E-06	4.29E-04	0.00E+00	8.38E-01
Hexane														1.76E-03	1.03E-02	0.00E+00	0.00E+00
Lead	1.40E-05	5.58E-02	2.79E-02	1.40E-05	5.58E-02	1.40E-02	4.19E-02										4.19E-02
Manganese	7.90E-04	3.15E+00	1.58E+00	7.90E-04	3.15E+00	7.88E-01	2.36E+00										2.36E+00
Mercury	1.20E-06	4.79E-03	2.39E-03	1.20E-06	4.79E-03	1.20E-03	3.59E-03										3.59E-03
Naphthalene	3.50E-05	1.40E-01	6.98E-02	3.50E-05	1.40E-01	3.49E-02	1.05E-01							5.98E-07	3.49E-06	0.00E+00	1.05E-01
Nickel	4.60E-06	1.83E-02	9.17E-03	4.60E-06	1.83E-02	4.59E-03	1.38E-02										1.38E-02
PAH	4.00E-05	1.60E-01	7.98E-02	4.00E-05	1.60E-01	3.99E-02	1.20E-01	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04				1.20E-01
POM														8.66E-08	5.05E-07	0.00E+00	0.00E+00
Propylene Oxides																	0.00E+00
Selenium	2.50E-05	9.97E-02	4.99E-02	2.50E-05	9.97E-02	2.49E-02	7.48E-02										7.48E-02
Toluene								4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.78E-04	3.33E-06	1.95E-05	0.00E+00	6.70E-04
Xylenes								2.85E-04	6.78E-04	1.36E-04	1.93E-04	2.84E-03	3.28E-04				4.62E-04
	Total Emissions		2.57E+00			1.28E+00	3.85E+00			1.84E-03			2.66E-03			0.00E+00	3.86E+00

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
3. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
4. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
6. In the pre-onsite natural gas availability scenario, the duct burners cannot fire natural gas and are thus not included in the HAP emission calcualtion.

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Post-Onsite Natural Gas Availability **Simple Cycle Operations**

Table C-15: Emissions Calculations with CTGs firing Natural Gas Only

INPUTS

No. of CTGs
2

Heat Input (MBtu/hr)				
CTG (GAS) [1]	CTG (ULSFO) [1]	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	2.38	14.70	5.837

Hours of Operation per Unit				
CTG (GAS)	CTG (ULSFO)	Fire Pump	Emergency Engine	Fuel Heater
3500	0	400	230	8760

	Combustion Turbines							Fire Pump			Emergency Diesel Engine Generator			Fuel Heater			
Pollutant	CTG (Natural Gas) Emission factor [2] lb/MBtu	2 CTGs Natural Gas PTE (lb/hr)	2 CTGs Natural Gas PTE (tpy)	CTG (ULSFO) Emission factor [3] lb/MBtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSFO PTE (tpy)	2 CTGs Total NG+ULSFO PTE (lb/hr)	Fire Pump E.F.[4] lb/MBtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[5] lb/MBtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[6] lb/MBtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Total PTE tpy
1,3-Butadiene	4.30E-07	1.55E-03	2.72E-03	1.60E-05	6.38E-02	0.00E+00	6.54E-02	3.91E-05	9.31E-05	1.86E-05							2.74E-03
Acetaldehyde	4.00E-05	1.44E-01	2.53E-01				1.44E-01	7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05				2.53E-01
Acrolein	6.40E-06	2.31E-02	4.04E-02				2.31E-02	9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05				4.05E-02
Arsenic				1.10E-05	4.39E-02	0.00E+00	4.39E-02										0.00E+00
Benzene	1.20E-05	4.33E-02	7.58E-02	5.50E-05	2.19E-01	0.00E+00	2.63E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	5.26E-05	7.76E-02
Beryllium				3.10E-07	1.24E-03	0.00E+00	1.24E-03										0.00E+00
Cadmium				4.80E-06	1.91E-02	0.00E+00	1.91E-02										0.00E+00
Chromium				1.10E-05	4.39E-02	0.00E+00	4.39E-02										0.00E+00
Chromium (VI)																	0.00E+00
Dichlorobenzene														1.18E-06	6.87E-06	3.01E-05	3.01E-05
Ethylbenzene	3.20E-05	1.16E-01	2.02E-01				1.16E-01										2.02E-01
Formaldehyde[7]	1.01E-04	3.63E-01	6.36E-01	2.80E-04	1.12E+00	0.00E+00	1.48E+00	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	1.88E-03	6.38E-01
Hexane														1.76E-03	1.03E-02	4.51E-02	4.51E-02
Lead				1.40E-05	5.58E-02	0.00E+00	5.58E-02										0.00E+00
Manganese				7.90E-04	3.15E+00	0.00E+00	3.15E+00										0.00E+00
Mercury				1.20E-06	4.79E-03	0.00E+00	4.79E-03										0.00E+00
Naphthalene	1.30E-06	4.69E-03	8.22E-03	3.50E-05	1.40E-01	0.00E+00	1.44E-01							5.98E-07	3.49E-06	1.53E-05	8.23E-03
Nickel				4.60E-06	1.83E-02	0.00E+00	1.83E-02										0.00E+00
PAH	2.20E-06	7.95E-03	1.39E-02	4.00E-05	1.60E-01	0.00E+00	1.67E-01	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04				1.43E-02
POM														8.65E-08	5.05E-07	2.21E-06	2.21E-06
Propylene Oxides	2.90E-05	1.05E-01	1.83E-01				1.05E-01										1.83E-01
Selenium				2.50E-05	9.97E-02	0.00E+00	9.97E-02										0.00E+00
Toluene	1.30E-04	4.69E-01	8.22E-01				4.69E-01	4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	8.52E-05	8.22E-01
Xylenes	6.40E-05	2.31E-01	4.04E-01				2.31E-01	2.85E-04	6.78E-04	1.36E-04	1.93E-04	2.84E-03	3.26E-04				4.05E-01
	Total Emissions		**2.64E+00**			**0.00E+00**				**1.84E-03**			**2.66E-03**			**4.72E-02**	**2.69E+00**

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
6. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
7. Formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Addendum Database (Combustion Turbine Emissions Database v.5. URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.

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Table C-16: Emissions Calculations with CTGs Firing Natural Gas and ULSFO

INPUTS

No. of CTGs	No. of HRSGs
2	2

Heat Input (MBtu/hr)						
SCCT (GAS) [1]	SCCT (ULSFO) [1]	CCCT (GAS) [1]	CCCT (ULSFO) [1]	Duct Burner (GAS)	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	1778.3	1947.5	188.6	2.38	14.70	5.837

Hours of Operation per Unit							
SCCT (GAS)	SCCT (ULSFO)	CCCT (GAS)	CCCT (ULSFO)	Duct Burner (GAS)	Fire Pump	Emergency Engine	Fuel Heater
3000	500	4760	500	5260	400	230	8760

		Simple Cycle Combustion Turbines						Combined Cycle Combustion Turbine/HRSG								Ancillary Units									Total	SCCT Scenario	CCCT Scenario
Pollutant	CTG (Natural Gas) Emission Factor [2] lb/MMbtu	2 SCCTs Natural Gas PTE (lb/hr)	2 SCCTs Natural Gas PTE (tpy)	SCCT (ULSFO) Emission factor [3] lb/MBtu	2 SCCT CTGs ULSFO PTE (lb/hr)	2 SCCTs ULSFO PTE (tpy)	2 SCCTs Total NG+ULSFO PTE (tpy)	2 CCCTs Natural Gas PTE (lb/hr)	2 CCCTs Natural Gas PTE (tpy)	2 CCCTs ULSFO PTE (lb/hr)	2 CCCTs ULSFO PTE (tpy)	Duct Burner E.F.[4] lb/MMBtu	Duct Burner PTE (lb/hr)	Duct Burner PTE tpy	2 CCCTs Total NG+ULSFO PTE (tpy)	Fire Pump E.F.[5] lb/MBtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[6] lb/MBtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[4] lb/MBtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Anc. Eqpt PTE tpy	Total [8] PTE tpy	Total [8] PTE tpy
1,3-Butadiene	4.30E-07	1.55E-03	2.33E-03	1.50E-05	6.38E-02	1.50E-02	1.83E-02	1.53E-03	3.64E-03	6.23E-02	1.56E-02				1.92E-02	3.01E-05	9.31E-05	1.86E-05								1.86E-05	1.83E-02	1.92E-02
Acetaldehyde	4.00E-05	1.44E-01	2.17E-01				2.17E-01	1.42E-01	3.39E-01						3.39E-01	7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05					4.08E-04	2.17E-01	3.39E-01
Acrolein	6.40E-06	2.31E-02	3.47E-02				3.47E-02	2.28E-03	5.42E-02						5.42E-02	9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05					5.74E-05	3.47E-02	5.42E-02
Arsenic				1.10E-05	4.39E-02	1.10E-02	1.10E-02			4.28E-02	1.07E-02				1.07E-02												1.10E-02	1.07E-02
Benzene	1.20E-05	4.33E-02	6.50E-02	5.50E-06	2.19E-01	5.48E-02	1.20E-01	4.27E-02	1.02E-01	2.14E-01	5.36E-02	2.06E-06	3.88E-04	1.02E-03	1.56E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	5.26E-05	1.81E-03	1.22E-01	1.98E-01
Beryllium				3.10E-07	1.24E-03	3.06E-04	3.06E-04			1.21E-03	3.02E-04				3.02E-04												3.06E-04	3.02E-04
Cadmium				4.80E-06	1.91E-02	4.79E-03	4.79E-03			1.87E-02	4.67E-03				4.67E-03												4.79E-03	4.67E-03
Chromium				1.10E-05	4.39E-02	1.10E-02	1.10E-02			4.28E-02	1.07E-02				1.07E-02												1.10E-02	1.07E-02
Chromium (VI)															0.00E+00												0.00E+00	0.00E+00
Dichlorobenzene												1.18E-06	2.22E-04	5.84E-04	5.84E-04												5.84E-04	5.14E-04
Ethylbenzene	3.20E-05	1.16E-01	1.73E-01				1.73E-01	1.14E-01	2.71E-01						2.71E-01												1.73E-01	2.71E-01
Formaldehyde [7]	1.01E-04	3.63E-01	5.45E-01	2.80E-04	1.12E+00	2.79E-01	8.24E-01	3.55E-01	8.51E-01	1.09E+00	2.73E-01	7.35E-05	1.39E-02	3.65E-02	1.16E+00	1.18E-03	2.81E-03	5.62E-04	7.80E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	1.68E-03	2.57E-03	8.26E-01	1.16E+00
Hexane												1.76E-03	3.33E-01	8.75E-01	8.75E-01							1.76E-03	1.03E-02	4.51E-02	4.51E-02	4.61E-02	9.20E-01
Lead				1.40E-05	5.58E-02	1.40E-02	1.40E-02			5.45E-02	1.36E-02				1.36E-02												1.40E-02	1.36E-02
Manganese				7.90E-04	3.15E+00	7.88E-01	7.88E-01			3.08E+00	7.69E-01				7.69E-01												7.88E-01	7.69E-01
Mercury				1.20E-06	4.79E-03	1.20E-03	1.20E-03			4.67E-03	1.17E-03				1.17E-03												1.20E-03	1.17E-03
Naphthalene	1.30E-06	4.69E-03	7.04E-03	3.50E-05	1.40E-01	3.49E-02	4.19E-02	4.62E-03	1.10E-02	1.39E-01	3.41E-02	5.98E-07	1.13E-04	2.97E-04	4.54E-02							5.98E-07	3.49E-06	1.53E-05	1.53E-05	4.20E-02	4.54E-02
Nickel				4.60E-06	1.83E-02	4.58E-03	4.58E-03			1.79E-02	4.48E-03				4.48E-03												4.58E-03	4.48E-03
PAH	2.20E-06	7.95E-03	1.19E-02	4.00E-05	1.60E-01	3.99E-02	5.18E-02	7.82E-03	1.86E-02	1.56E-01	3.90E-02				5.76E-02	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04					4.38E-04	5.22E-02	5.80E-02
POM												8.65E-08	1.63E-06	4.29E-05	4.29E-05							8.65E-08	5.05E-07	2.21E-06	2.21E-06	2.21E-06	4.51E-05
Propylene Oxides	2.90E-05	1.05E-01	1.57E-01				1.57E-01	1.03E-01	2.45E-01						2.45E-01												1.57E-01	2.45E-01
Selenium				2.50E-05	9.97E-02	2.49E-02	2.49E-02			9.74E-02	2.43E-02				2.43E-02												2.49E-02	2.43E-02
Toluene	1.30E-04	4.69E-01	7.04E-01				7.04E-01	4.62E-01	1.10E+00			3.33E-06	6.20E-04	1.65E-03	1.10E+00	4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	8.52E-05	7.35E-04	7.05E-01	1.10E+00
Xylenes	6.40E-05	2.31E-01	3.47E-01				3.47E-01	2.28E-01	5.42E-01						5.42E-01	2.85E-04	6.76E-04	1.36E-04	1.93E-04	2.84E-03	3.26E-04				4.62E-04	3.47E-01	5.42E-01
	Total Emissions		2.26E+00			1.28E+00	3.55E+00		3.54E+00		1.25E+00			9.15E-01	5.71E+00			1.84E-03			2.66E-03			4.72E-02	5.17E-02	3.60E+00	5.76E+00

Worst Case total HAP PTE occurs when each SCCT operates 3000 hrs/yr on gas and 500 hrs/yr on ULSFO; and each CCCT operates 4760 hrs/yr on gas and 500 hrs/yr on ULSFO, respectively.

Worst Case Total HAP PTE [8]	9.31E+00	tpy

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion
5. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines
6. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
7. Formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5. URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.
8. SCCT total assumed based on HAP emissions from SCCT operations and ancillary equipment. CCCT total assumes HAP emissions from SCCT operations ans ancillary equipment. Worst Case total HAP emissions includes emissiosn from SCCTs, CCCTs and ancillary equipment. Ancillary equipment are not double counted.

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Post-Onsite Natural Gas Availability

Table C-16: Emissions Calculations with CTGs Firing Natural Gas and ULSFO

INPUTS

No. of CTGs	No. of HRSGs
2	2

Heat Input (MBtu/hr)							
SCCT (GAS) [1]	SCCT (ULSFO) [1]	CCCT (GAS) [1]	CCCT (ULSFO) [1]	Duct Burner (GAS)	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	1778.3	1947.5	188.6	2.38	14.70	5.837

Hours of Operation per Unit							
SCCT (GAS)	SCCT (ULSFO)	CCCT (GAS)	CCCT (ULSFO)	Duct Burner (GAS)	Fire Pump	Emergency Engine	Fuel Heater
0	0	8760	0	8760	400	230	8760

		Simple Cycle Combustion Turbines						Combined Cycle Combustion Turbine/HRSG							Ancillary Units								Total	SCCT Scenario	CCCT Scenario
Pollutant	CTG (Natural Gas) Emission Factor	2 SCCTs Natural Gas PTE (lb/hr)	2 SCCTs Natural Gas PTE (tpy)	SCCT (ULSFO) Emission factor [2] lb/MBtu	2 SCCT CTGs ULSFO PTE (lb/hr)	2 SCCTs ULSFO PTE (tpy)	2 SCCTs Total NG+ULSFO PTE (tpy)	2 CCCTs Natural Gas PTE (lb/hr)	2 CCCTs Natural Gas PTE (tpy)	2 CCCTs ULSFO PTE (lb/hr)	2 CCCTs ULSFO PTE (tpy)	Duct Burner E.F.[6] lb/MBtu	Duct Burner PTE (lb/hr)	Duct Burner PTE tpy	2 CCCTs Total NG+ULSFO PTE (tpy)	Fire Pump E.F.[4] lb/MBtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[5] lb/MBtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[6] lb/MBtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Anc. Eqpt PTE tpy	Total [8] PTE tpy	Total [8] PTE tpy
1,3-Butadiene	4.30E-07	1.55E-03	0.00E+00	1.60E-05	6.38E-02	0.00E+00	0.00E+00	1.53E-03	6.70E-03	6.23E-02	0.00E+00				6.70E-03	3.91E-05	9.31E-05	1.86E-05								1.86E-05	1.86E-05	6.72E-03
Acetaldehyde	4.00E-05	1.44E-01	0.00E+00				0.00E+00	1.42E-01	6.23E-01						6.23E-01	7.77E-04	1.85E-03	3.65E-04	2.52E-03	3.01E-04	4.26E-05				4.09E-04	4.09E-04	6.24E-01
Acrolein	6.40E-06	2.31E-02	0.00E+00				0.00E+00	2.28E-02	9.97E-02						9.97E-02	9.26E-06	2.20E-04	4.40E-05	7.98E-06	1.16E-04	1.33E-05				5.74E-05	5.74E-05	9.98E-02
Arsenic				1.10E-05	4.39E-02	0.00E+00	0.00E+00			2.28E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Benzene	1.20E-05	4.33E-02	0.00E+00	5.50E-05	2.19E-01	0.00E+00	0.00E+00	4.27E-02	1.87E-01	2.14E-01	0.00E+00	2.06E-06	3.88E-04	1.70E-03	1.89E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	5.26E-05	1.81E-03	1.81E-03	1.90E-01
Beryllium				3.10E-07	1.24E-03	0.00E+00	0.00E+00			1.21E-03	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Cadmium				4.80E-06	1.91E-02	0.00E+00	0.00E+00			1.87E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Chromium				1.10E-05	4.39E-02	0.00E+00	0.00E+00			4.28E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Chromium (VI)															0.00E+00												
Dichlorobenzene												1.18E-06	2.22E-04	9.72E-04	9.72E-04							1.18E-06	6.87E-06	3.01E-06	3.01E-06	3.01E-03	1.00E-03
Ethylbenzene	3.20E-05	1.16E-01	0.00E+00				0.00E+00	1.14E-01	4.98E-01						4.98E-01											0.00E+00	4.98E-01
Formaldehyde[7]	1.01E-04	3.63E-01	0.00E+00	2.80E-04	1.12E+00	0.00E+00	0.00E+00	3.58E-01	1.57E+00	1.09E+00	0.00E+00	7.36E-06	1.39E-02	6.07E-02	1.63E+00	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	1.88E-03	2.57E-03	2.57E-03	1.63E+00
Hexane												1.76E-03	3.33E-01	1.46E+00	1.46E+00							1.76E-03	1.03E-02	4.51E-02	4.51E-02	4.51E-02	1.52E+00
Lead				1.40E-05	5.58E-02	0.00E+00	0.00E+00			5.45E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Manganese				7.90E-04	3.15E+00	0.00E+00	0.00E+00			3.08E+00	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Mercury				1.20E-06	4.79E-03	0.00E+00	0.00E+00			4.67E-03	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Naphthalene	1.30E-06	4.69E-03	0.00E+00	3.50E-05	1.40E-01	0.00E+00	0.00E+00	4.62E-03	2.03E-02	1.38E-01	0.00E+00	5.98E-07	1.13E-04	4.94E-04	2.07E-02							5.98E-07	3.49E-06	1.53E-05	1.53E-05	1.53E-05	2.08E-02
Nickel				4.60E-06	1.83E-02	0.00E+00	0.00E+00			1.79E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
PAH	2.20E-06	7.95E-03	0.00E+00	4.00E-05	1.60E-01	0.00E+00	0.00E+00	7.82E-03	3.43E-02	1.56E-01	0.00E+00				3.43E-02	1.58E-04	4.00E-04	8.00E-05	2.72E-04	3.12E-03	3.58E-04				4.38E-04	4.38E-04	3.47E-02
POM												8.65E-08	1.63E-05	7.14E-05	7.14E-05							8.65E-08	5.05E-07	2.21E-06	2.21E-06	2.21E-06	7.36E-05
Propylene Oxides	2.90E-05	1.05E-01	0.00E+00				0.00E+00	1.03E-01	4.52E-01						4.52E-01											0.00E+00	4.52E-01
Selenium				2.50E-05	9.97E-02	0.00E+00	0.00E+00			9.74E-02	0.00E+00				0.00E+00											0.00E+00	0.00E+00
Toluene	1.30E-04	4.69E-01	0.00E+00				0.00E+00	4.62E-01	2.03E+00			3.33E-06	6.29E-04	2.75E-03	2.03E+00	4.09E-04	9.73E-04	1.46E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	8.52E-05	7.55E-04	7.55E-04	9.97E-01
Xylenes	6.40E-05	2.31E-01	0.00E+00				0.00E+00	2.28E-01	9.97E-01						9.97E-01	2.85E-04	6.76E-04	1.46E-04	1.93E-04	2.84E-03	3.26E-04				4.62E-04	4.62E-04	9.97E-01
	Total Emissions		0.00E+00			0.00E+00	0.00E+00		6.51E+00		0.00E+00			1.52E+00	8.03E+00			1.84E-03			2.66E-03			4.72E-02	5.17E-02	5.17E-02	8.09E+00

Worst Case total HAP PTE occurs when each SCCT operates 3000 hrs/yr on gas and 500 hrs/yr on ULSFO; and each CCCT operates 4760 hrs/yr on gas and 500 hrs/yr on ULSFO, respectively.

Worst Case Total HAP PTE[8]	8.09E+00 tpy

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
6. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
7. Formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5. URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of
8. SCCT total assumed based on HAP emissions from SCCT operations and ancillary equipment. CCCT total assumes HAP emissions from SCCT operations ans ancillary equipment. Worst Case total HAP emissions includes emissiosn from SCCTs, CCCTs and ancillary equipment. Ancillary equipment are not double counted.

Natural Gas

Emission Factor Report for Formaldehyde with All Lean Premix

03-Apr-08

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF	(lb/MMBtu)	Count of Runs	ND Count	Control Device
27	General Electric	Frame 6	42.5	100	<	5.72E-05	3	1	DLN unit; also SCR and ammonia injection
324.2.1	General Electric	Frame 7F	165	100		3.04E-05	3	0	Lean Premix and SCR
324.1.1	General Electric	Frame 7F	165	100		2.16E-05	3	0	Lean Premix and SCR
321.4	General Electric	Frame 7F	130	100		9.78E-05	3	0	Lean Premix
320.3	General Electric	Frame 7F	130	100		2.43E-04	3	0	Lean Premix
319.2	General Electric	Frame 7F	130	100		1.10E-04	3	0	Lean Premix (Dry Low NOx)
314.3	Solar	Mars SoL	10.9	50		5.85E-04	3	0	Lean pre-mix (SoLoNOx)

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
314.2	Solar	Mars SoL	10.9	75	4.93E-05	3	0	Lean pre-mix (SoLoNOx)
314.1	Solar	Mars SoL	10.9	100	1.45E-05	3	0	Lean pre-mix (SoLoNOx)
				Avg EF =	**1.34E-04**			
				Count =	**9**			

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	GEC ULSFO Tank
City:	Jacksonville
State:	Florida
Company:	JEA
Type of Tank:	Vertical Fixed Roof Tank
Description:	JEA GEC ULSFO Tanks (Identical 1 and 2 Tanks) CCCT Operations

Tank Dimensions

Shell Height (ft):	35.00
Diameter (ft):	100.00
Liquid Height (ft) :	29.00
Avg. Liquid Height (ft):	29.00
Volume (gallons):	1,703,809.66
Turnovers:	4.32
Net Throughput(gal/yr):	7,360,000.00
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)	13.40
Radius (ft) (Dome Roof)	100.00

Breather Vent Settings

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

Meterological Data used in Emissions Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

GEC ULSFO Tank - Vertical Fixed Roof Tank
Jacksonville, Florida

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis fc Calcula
Distillate fuel oil no. 2	All	69.96	64.29	75.63	68.02	0.0090	0.0076	0.0107	130.0000			188.00	Option

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

GEC ULSFO Tank - Vertical Fixed Roof Tank
Jacksonville, Florida

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	204.80	293.47	498.27

Appendix D
BACT Analysis

Best Available Control Technology Analysis
for
JEA – Greenland Energy Center
Units 1 and 2
Combined Cycle Combustion Turbines

Submitted by

JEA

September 2008
Project No. 149588

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ENERGY WATER INFORMATION GOVERNMENT

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Acronym List

AQC	Air Quality Control
BACT	Best Available Control Technology
bhp	Brake Horsepower
bhph	Brake Horsepower Hour
Btu	British Thermal Unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CCCT	Combined Cycle Combustion Turbine
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DB	Duct Burner
FMPA	Florida Municipal Power Agency
FPL	Florida Power and Light Company
GEC	Greenland Energy Center
g/bhph	Grams per Brake Horsepower Hour
H_2SO_4	Sulfuric Acid Mist
h/yr	Hours per Year
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
kW	Kilowatt
kWh	Kilowatt Hour
LAER	Lowest Achievable Emission Rate
Lb/h	Pound per Hour
L/G	Liquid-To-Gas
LNB	Low NO_x Burner
MBtu	Million British Thermal Unit
MW	Megawatt
NESCAUM	Northeast States for Coordinated Air Use Management
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
OAQPS	Office of Air Quality Planning And Standards

OEM	Original Equipment Manufacturer
Pb	Lead
PM/PM_{10}	Particulate Matter/Particulate Matter Less than 10 Microns
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SARA	Superfund Amendments and Reauthorization Act of 1986
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Tubine Generator
tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1.0 Introduction and Executive Summary

JEA is proposing to convert the two simple cycle combustion turbines (CTs), Units 1 and 2, at the Greenland Energy Center (GEC) into a 2 x 1 combined cycle configuration. The GEC is located in southeastern Duval County, Florida and is currently undergoing construction permitting for the two simple cycle units. The combined cycle configuration will consist of the same two General Electric (GE) 7FA combustion turbines that are currently being permitted as simple cycle units, but will now each include a heat recovery steam generator (HRSG) with supplemental natural gas-fired duct burners. The simple cycle functionality of each combustion turbine will be retained post-combined cycle conversion. Having already been subject to major source permitting and a BACT determination, the proposed simple cycle combustion turbine stacks will function as a bypass stack for simple cycle operation after the combined cycle conversion. The proposed conversion Project will include the combined cycle conversion of the simple cycle units and a mechanical draft cooling tower. There will be no other additions to the ancillary units already included as part of the simple cycle operations.

Table 1-1 lists a summary of the proposed BACT determinations and associated emission rates for Units 1 and 2 combined cycle combustion turbine (CCCT) operation with supplemental duct burners. GEC Units 1 and 2 CCCT, also referred to as the Project, will fire natural gas primarily, with up to 500 hours per turbine per year of ultra-low sulfur fuel oil (ULSFO, 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 a per CCCT basis of firing natural gas for a maximum of 8,760 hours per year. Each unit will operate between 50 and 100 percent of full load.

It should be noted that the emissions for the BACT analysis are based on 100 percent load conditions at ambient air temperature of 59° F and 60 percent relative humidity (60% RH) (hereinafter referred to as ISO conditions).

The Project is classified as a New Source Review/Prevention of Significant Deterioration (NSR/PSD) major emission source, and as a result of the calculated potential emissions (See Section 2.4 of the air permit application document), is subject to a Best Available Control Technology (BACT) review for sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM)/PM_{10}, and sulfuric acid mist (H_2SO_4). The Project is not subject to review for volatile organic compounds (VOC), lead (Pb), hydrogen sulfide (H_2S), vinyl chloride, total fluorides, mercury, or total reduced sulfur compounds.

As required under the NSR/PSD regulations, the BACT analysis presented herein employed a "top-down," five-step analysis process to determine the appropriate emission

control technologies and emissions limitations for the Project. The BACT analysis was conducted for the GEC Units 1 and 2 combined cycle conversion and the mechanical draft cooling tower. The BACT analysis was conducted in accordance with the United States Environmental Protection Agency's (USEPA's) recommended methodology:

- Step 1--Identify All Control Technologies.
- Step 2--Eliminate Technically Infeasible Options.
- Step 3--Rank Remaining Control Technologies by Control Effectiveness.
- Step 4--Evaluate Most Effective Controls.
- Step 5--Select BACT.

Step 1--Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. Post-combustion controls would be the various add-on controls for the pollutant being controlled.

Step 2--Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to identify the technical feasibility of the control options identified in Step 1, which are evaluated with respect to source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined as a clearly documented case of a control option that has technical difficulties that would preclude the successful use of the control option because of physical, chemical, and engineering principles. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

In Step 2, the control option is identified as technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size under review (demonstrated). If the control option cannot be demonstrated, the analysis gets more involved. When determining if a control option has not been demonstrated, two key concepts need to be analyzed. The first concept, availability, is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by

vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, "applicability," is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

Step 3--Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information in regard to other control options that would provide less control.

Step 4--Evaluate Most Effective Controls

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as "Impact Analysis." The following impact analyses are performed:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which impacts the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental evaluation of alternatives. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology.

Examples of non-air quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to indicate the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters should be obtained from established sources that can be referenced. However, documented assumptions can be made in the absence of references for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. The cost-effectiveness compares the potential technologies on an economical basis. Two types of cost-effectiveness are considered in a BACT analysis: average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a good measure of viability when comparing technologies that have similar removal efficiencies.

Step 5–Select BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

As summarized in Table 1-1, the aforementioned BACT analysis process resulted in the following control technology and emissions level determinations for the Project's affected air emissions sources and pollutants. The ton per year emissions presented in Appendix C are proposed as BACT emission caps.

Table 1-1
BACT Determination Summary

Emission Unit: Nominal 547 MW and 524 MW Net CCCT Units 1 and 2 (2 X 1 F-Class PG7241FA) when firing natural gas and ULSFO, respectively

Pollutant	Control Technology	Emission Basis	Compliance Method	CEMS Avg. Period
NO_x	DLN/SCR (for natural gas combustion) WI/SCR (for ULSFO combustion)	Natural Gas: 2.0 ppmvd @ 15% O_2 ULSFO: 8.0 ppmvd @ 15% O_2	Stack Test, 3-Run Avg.	24-hr block
CO	Good Combustion Controls	Natural Gas: 7.6 ppmvd @ 15% O_2 with DBs; 4.1 ppmvd @ 15% O_2 w/o DBs; ULSFO: 8.0 ppmvd @ 15% O_2	Stack Test, 3-Run Avg.	24-hr block
PM/PM_{10}	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S) Good Combustion Practices	10% Opacity	USEPA Method 9 Fuel Sulfur Records	NA
SO_2	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S)	NA	Fuel Sulfur Records	NA
H_2SO_4	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S)	NA	Fuel Sulfur Records	NA

Emission Unit: Cooling Tower

Pollutant	Control Technology	Emission Basis
PM/PM_{10}	Drift Eliminators	0.0005% drift rate

CEMS = Continuous Emissions Monitoring System.
SCR = Selective Catalytic Reduction.
ULSFO = Ultra-low sulfur fuel oil

2.0 BACT Analysis Basis

This section describes the basis of the Project's BACT analysis, converting the two simple cycle CTs at the GEC into a 2 x 1 combined cycle configuration. Information provided in this section also includes details on the BACT methodology and approach, as well as the parameters and factors used in developing the analysis. The BACT analysis for GEC Units 1 and 2 CCCT operation is based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions for which this BACT analysis is based.

2.1 Regulatory Basis

The Clean Air Act Amendments of 1990 (CAA) established revised conditions for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed to control all pollutants regulated under the Act that are emitted in significant amounts from new major sources or major modifications.

The applicable state regulations governing this process define BACT 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).

To bring consistency to the BACT process, the USEPA provides as guidance to the states the use of a "top-down" approach to BACT determinations, which utilizes the five-step analysis process previously summarized. In practice, the top-down BACT analysis determines the most stringent control technology and emissions limitation combination available for a similar source or source category of emission units. At the head of the list in the top-down analysis methodology are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative that must be considered under the BACT analysis process.

The following informational databases, clearinghouses, and documents were used to identify recent control technology determinations for similar source categories and emission units for this BACT analysis:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Combustion Turbine Projects Spreadsheet.
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- Engineering design on other projects.

If it cannot be shown that the top level of control is infeasible (for a similar type source and fuel category) on the basis of technical, economic, energy, or environmental impact considerations, then that level of control must be declared to represent BACT for the respective pollutant and air emissions source. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and project-specific consideration of the aforementioned screening criteria (e.g., technical, economic, energy, and environmental considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS) for the affected air emissions source.

2.1.1 Applicable NSPS Emissions Limits

As previously discussed, a proposed BACT emissions limit, established in accordance with the top-down, five-step process, cannot be determined to be less stringent than the emissions limit(s) established by the applicable NSPS regulations found in 40 CFR Part 60. The following NSPS emissions limitations are applicable to the Project's air emissions sources.

2.1.1.1 NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. As new stationary CCCTs, GEC Units 1 and 2 will be subject to NSPS Subpart KKKK. Additionally, because the Project is subject to Subpart KKKK, it is not subject to Subpart GG or Subpart Da for the CT and HRSG duct burners, respectively. Applicable NSPS Subpart KKKK emissions limitations for the Project are as follows:

- NO_x--15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh) – new turbines firing natural gas with > 850 MBtu/hr heat input.
- NO_x--42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh) – new turbines firing fuel oil with > 850 MBtu/hr heat input.
- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

2.2 Unit Operations and Baseline Emissions Basis

GEC Units 1 and 2 CCCT will fire natural gas primarily, with up to 500 hours per turbine per year of ULSFO as a backup fuel. The duct burners will utilize only natural gas as the fuel source. Emissions for the BACT analysis are based on a per CCCT basis firing natural gas a maximum of 8,760 hours per year. The unit will operate between 50 and 100 percent of full load.

2.2.1 GEC Units 1 and 2 CCCT

Table 2-1 presents the BACT design basis for the Project's CCCT. Table 2-2 shows the baseline emission rates for each CCCT at 100 percent base load at the ISO inlet air temperature of 59° F for natural gas and sixty percent relative humidity (60% RH), hereinafter referred to as ISO conditions. The emissions shown in Table 2-2 are based on the use of dry low NO_x burners during natural gas firing with the operation of the natural gas fired duct burners at 100 percent load. The duct burners will fire only natural gas. The lb/MBtu values are based on the higher heating value (HHV) of the expected fuel to be fired and are based on the combined heat input to the combustion turbine and the duct burners. Table 2-3 shows the uncontrolled emissions for each CCCT.

GEC Units 1 and 2 CCCT will fire natural gas 8,760 hours per year with up to 500 hours firing ultra-low sulfur fuel oil (ULSFO) with 0.0015 percent sulfur by weight as a backup fuel. However, consistent with previous applications and determinations for combined cycles with very limited backup fuel capability, this BACT analysis is based on 100 percent operation on natural gas.

Table 2-1
Combustion Turbine Design Basis[1]

Size	Nominal 547 MW and 524 MW net CCCT Units 1 and 2 (2 X 1 F-Class PG7241FA) when firing natural gas and ULSFO, respectively
Combustion Turbine Generator (CTG) Heat Input	1,778.3 MBtu/h[1]
HRSG Duct Burners Heat Input	188.6 MBtu/h[1]
Operating Hours	8,760 h/yr
Fuel	Natural Gas

[1]Based on the Higher Heating Value when firing Natural Gas, 100% Load, Duct Firing, at ISO conditions.

Table 2-2
Baseline Emission Rates for each CCCT -- GEC Units 1 or 2

Emission Parameter	Units 1[a] or 2[a] Natural Gas, 100% Load, Duct Firing, at ISO Conditions
NO_x, ppmvd at 15% O_2	10.3
NO_x, lb/h	72.7
NO_x, lb/MBtu (HHV)	0.0369
CO, ppmvd at 15% O_2	7.6
CO, lb/h	32.7
CO, lb/MBtu (HHV)	0.0166
PM/PM_{10} (front and back), lb/h[b]	29.1
PM/PM_{10} (front and back), lb/MBtu (HHV)[b]	0.0148
SO_2, lb/h[c]	8.01
SO_2, lb/MBtu (HHV)[c]	0.0041
H_2SO_4, lb/h[b]	4.88
H_2SO_4, lb/MBtu[b]	0.00274

[a]Emissions are based on firing natural gas in the CT and HRSG duct burners at 100 percent of base load at ISO Conditions.

[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 burners.

[c]SO_2 values include the effects of 3 percent SO_2 oxidation in the Selective Catalytic Reduction System. Based on a natural gas sulfur content of 2 grains/100 scf

Table 2-3
GEC Units 1 or 2 CCCT Baseline Uncontrolled Emissions
(per CT)

Emission Parameter	Natural Gas Firing[a]
NO_x, tons per year (tpy)	318.43
CO, tpy	143.23
PM/PM_{10} (front and back), tpy	127.46
SO_2, tpy	35.08
H_2SO_4, tpy	21.37

[a]GEC Units 1 or 2 CCCT emissions are based on firing natural gas in the CT and HRSG duct burners at 100 percent of base load at ISO Conditions.

2.3 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 2-11 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 2-4
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	10
Escalation, percent	2.5
Present Worth Discount Rate, percent	5.0
Economic Life, years	25
Capital Recovery Factor, (25 years)	0.07095
SCR Catalyst Life, years	3
$SCONO_x$ Catalyst Life, years	5
CO Catalyst Life, years	6
Catalyst Capital Recovery Factor (3 years)	0.3672
Catalyst Capital Recovery Factor (6 years)	0.1970
$SCONO_x$ Catalyst Capital Recovery Factor (5 years)	0.2310
Labor Cost, $/man-hour (2008)	53
Natural Gas Cost, $/MBtu (2008)	8.10
Aqueous Ammonia Cost, $/ton (2008)	194
Energy Cost, $/kWh (2008)	0.063
Sales Tax, percent	N/A

3.0 GEC Units 1 and 2 NO_x and CO BACT Analysis

This section presents the top-down, five-step BACT process used to evaluate and determine the Project's NO_x and CO emissions limits for GEC Units 1 or 2 CCCT. As this analysis will demonstrate, the proposed NO_x BACT was determined to be the use of selective catalytic reduction to achieve an emission limit of 2 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. The proposed CO 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.

3.1 Step 1--Identify All NO_X Control Technologies

The first step in a top-down analysis, according to the EPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the NO_x emissions limit that is being evaluated. The results of this search for all combined-cycle combustion turbines are listed in Attachment 1: NO_X Control Technology Review List.

NO_x is defined as the combination of nitrogen oxide (NO) and nitrogen dioxide (NO_2). Typically, the NO_x that is formed in combustion turbines consists of 60 percent NO, with the balance occurring as NO_2. 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.

3.1.1 Water or Steam Injection

NO_x emissions from GEC Units 1 or 2 CCCT 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. Furthermore, this in-combustor control technology is typically used when firing fuel oil, or on much smaller units.

3.1.2 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.

3.1.3 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.

3.1.4 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. SNCR systems can use either ammonia (Thermal $DeNO_x$) or urea (NO_xOUT) as reagents.

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 1,550° to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Injection of reagent below this temperature window results in excessive ammonia emissions (ammonia slip). Injection of reagent above the temperature window results in increased NO_x emissions.

The exhaust temperature at the exit of the combustion turbine is between 1074° to 1200° F. Therefore, the exhaust temperature 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.

3.1.5 SCONO$_x$

A second, post-combustion technology from EmeraChem, LLC is EM$_X$™ ($SCONO_x$), which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. EmeraChem purchased $SCONO_X$ from Goal Line Environmental Technologies and ABB Alstom Power.

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. EmeraChem 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.

3.1.6 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 GEC Units 1 and 2 CCCTs, 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 GEC Units 1 and 2 CCCTs. 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.

3.2 Step 1--Identify All CO Control Technologies

The first step in a top-down analysis, according to the USEPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the CO emission limit that is being evaluated. The results of this search for all combined-cycle combustion turbines are listed in Attachment 2: CO Control Technology Review List.

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.

3.2.1 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.

3.2.2 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 a significant amount of the CO

emissions. A 73.7 percent CO reduction rate (i.e. 7.6 ppm to 2.0 ppm) has been assumed for this BACT analysis.

3.2.3 $SCONO_x$

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.

3.3 Step 2--Eliminate Technically Infeasible NO_X Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the NO_X BACT analysis and determine if they are technically feasible. Table 3-1 summarizes the evaluation of the technically feasible NO_X options.

3.3.1 Water or Steam Injection

Water or steam injection can be an effective NO_X control method for a turbine burning natural gas or fuel oil. However, demineralized water must be used and additional capital cost is required because an onsite demineralized system must be built and the annual operation of this system can be a significant expense in the unit operation. The development of dry low-NO_x burners has replaced the use of wet controls, except for certain cases, such as oil firing. New dry low-NO_X burners can achieve lower levels of NO_X compared to wet controls. Since GEC Units 1 and 2 CCCTs will fire natural gas as the primary fuel with ULSFO as a backup, water injection will only be used during ULSFO firing and will not be evaluated for the primary operating case of natural gas in this BACT analysis.

3.3.2 Dry Low-NO_x Burners

Dry low-NO_x burners are a demonstrated technology of controlling NO_X emissions from a combined-cycle combustion turbine and commercially available from several vendors. Dry low-NO_X burners are considered technically feasible and will be considered further.

3.3.3 XONON

Although XONON 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 GEC Units 1 and 2 CCCTs. 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 GEC Units 1 and 2 CCCTs. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

3.3.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) optimum temperature range for injection of ammonia or urea is 1,550° to 1,900° F. The exhaust temperature at the exit of the combustion turbine is between 1074° to 1200° F. Therefore, the exhaust temperature 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.

3.3.5 SCONO$_x$

The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. However, EmeraChem, LLC is EM$_X$™ (SCONO$_x$) offers their product for GE 7FAs which makes it available. In addition, SCONO$_X$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, SCONO$_x$ will be evaluated in the BACT for NO_x control.

3.3.6 Selective Catalytic Reduction

Selective Catalyst Reduction (SCR) systems are a demonstrated technology of controlling NO_X emissions from a combined-cycle combustion turbine and commercially

available from several vendors. SCR systems are considered technically feasible and will be considered further.

Table 3-1
Summary of Step 2--Eliminate Technically Infeasible Options

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Water or Steam Injection	Yes	No – Wet injection has limited NO_X removal. Not a primary control technology for natural gas fired turbines.
Dry Low-NO_X Burners	Yes	Yes
XONON	Yes	No – There are no documented installations on utility sized combustion turbines firing natural gas.
SNCR	Yes	No – The exhaust temperature of the combustion turbine is less than the SNCR's optimum temperature range.
$SCONO_X$	Yes	Yes
SCR	Yes	Yes

3.4 Step 2-Eliminate Technically Infeasible CO Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the CO BACT analysis and determine if they are technically feasible. Table 3-2 summarizes the evaluation of the technically feasible CO options.

3.4.1 Dry Low-NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state of the art DLN burners are a demonstrated technology of controlling CO emissions from a simple-cycle combustion turbine and commercially available from several vendors. DLN

burners and good combustion control are considered technically feasible and will be considered further.

3.4.2 CO Oxidation Catalyst

CO oxidation catalysts are a demonstrated technology of controlling CO emissions from a simple-cycle combustion turbine and commercially available from several vendors. CO oxidation catalysts are considered technically feasible and will be considered further.

3.4.3 $SCONO_x$

The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. However, EmeraChem, LLC is EM_X™ ($SCONO_x$) offers their product for GE 7FAs which makes it available. In addition, $SCONO_X$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for CO control.

Table 3-2
Summary of Step 2--Eliminate Technically Infeasible CO Options

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
DLN Burners and Good Combustion Control	Yes	Yes
CO Oxidation Catalyst	Yes	Yes
$SCONO_X$	Yes	Yes

3.5 Step 3-Rank Combined NO_X and CO Control Technology Effectiveness

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 the Project. 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 the Project 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 2.0 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 2.0 ppmvd.

The following evaluation considers energy, environmental, and economic impacts for the NO_x and CO combined technology scenarios evaluated. Table 3-3 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.

Table 3-3
Estimated NO_x and CO Emissions from Alternate Control Technologies for GEC Units 1 or 2 CCCTs
(per CT)

	Control Technology Alternatives		
	LNB/Good Combustion Controls	SCR/CO Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	10.3	2.0	2.0
lb/h	72.7	14.1	14.1
tons per year (tpy)[a]	318.4	61.8	61.8
percent reduction	N/A	80.6%	80.6%
NO_x Emission Reduction (tpy)	Base	256.6	256.6
CO Emissions			
ppmvd (at 15 percent O_2)	7.6	2.0	2.0
lb/h	32.7	8.6	8.6
tons per year (tpy)[a]	143.2	37.7	37.7
percent reduction	N/A	73.7%	73.7%
CO Emission Reduction (tpy)	Base	105.5	105.5

[a]Total emissions are based on 8,760 hours per year firing natural gas, 100% Load, Duct Firing, at ISO Conditions.

3.6 Step 4-Evaluate Most Effective Combined NO_X and CO Controls

In the following subsections, the NO_X and CO combined control technologies are evaluated in a comparative approach with respect to their energy, environmental, and economic impacts on GEC Units 1 and 2 CCCT. The following are the evaluated technologies: $SCONO_X$, SCR, and Oxidation Catalyst.

3.6.1 $SCONO_x$ 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 for each CCCT 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 for each combustion turbine. 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 each $SCONO_x$ system. This 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.

3.6.2 $SCONO_x$ 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}.

3.6.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of GEC Units 1 and 2 CCCTs. 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 each combustion turbine. The SCR system would add about 2.6 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 each CCCT by approximately 492 kW.

3.6.4 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 GEC Units 1 and 2 CCCT stacks are 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 proposed an ammonia slip of 5 ppmvd for Treasure Coast, a combined cycle combustion turbine unit utilizing SCR. Based on the recent Treasure Coast 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 GEC Units 1 and 2 CCCTs.

3.6.5 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 each combustion turbine output by approximately 227 kW. The cost of lost power revenue due to the backpressure is included in the economic analysis.

3.6.6 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.

3.6.7 Economic Impacts for SCR (2.0 ppmvd)/ Oxidation Catalyst Versus SCONOx

The use of an SCR/oxidation catalyst or $SCONO_x$ has significant economic impacts to GEC Units 1 and Unit 2 CCCTs. An analysis of the economic impact is provided in this section.

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

Table 3-4 presents the capital costs for installing an SCR/oxidation catalyst and $SCONO_x$ system on each CCCT during natural gas firing to achieve a NO_x outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd. Note, the same SCR/oxidation catalyst and $SCONO_x$ systems have been designed to accommodate firing natural gas as the primary fuel and ULSFO as a backup fuel. The cost of the SCR/oxidation catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing, ductwork; 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.[10] 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 small boilers and municipal waste combustors.[11,12]. 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 each CCCT controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively is estimated to be $5,243,000.

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

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

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

[12]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.

capital investment for each CCCT controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively is estimated to be $27,912,000.

Table 3-4
NO_x/CO Combined Control Alternative Capital Cost ($) for Each CCCT
(GEC Units 1 and 2)

	DLN	$SCONO_x$ ($)	SCR/OX Cat ($)	Remarks
Direct Capital Cost				Cost based on emissions in Table 3-3
Catalysts	N/A	Included	1,717,000	Est. from BASF/CERAM
Catalyst R. Housing /Ductwork	N/A	Included	705,000	Estimated from Turner EnviroLogic
$SCONO_x$ System	N/A	16,000,000	0	Vendor Estimate
Control/Instrumentation	N/A	150,000	195,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Injection)	N/A	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**16,150,000**	**3,602,000**	
Sales Tax		0	0	Not applicable to JEA
Freight	N/A	1,615,000	361,000	10% of PEC
Balance of Plant	N/A	5,491,000	1,081,000	30% of PEC. See text for background information on this item
Total Direct Cost (DC)	**N/A**	**23,256,000**	**5,044,000**	
Indirect Capital Costs				
Contingency	N/A	2,326,000	504,000	10% of DC
Engineering and Supervision	N/A	2,326,000	504,000	10% of DC for $SCONO_x$. 10% of DC for SCR and 10% of DC for CO catalyst.
Construction & Field Expense	N/A	1,163,000	253,000	5% of DC
Construction Fee	N/A	2,326,000	504,000	10% of DC
Start-up Assistance	N/A	465,000	101,000	2% of DC
Performance Test	N/A	50,000	50,000	Assumed $50,000 emission test.
Total Indirect Capital Costs (IC)	**Base**	**8,656,000**	**1,916,000**	
Installed Costs (DC+IC)	**Base**	**31,912,000**	**6,960,000**	
Less Catalyst	Base	4,000,000	1,717,000	Catalyst is viewed as an O&M value.
Total Capital Investment (TCI)	**Base**	**27,912,000**	**5,243,000**	TCI = DC + IC – Catalyst

3.6.7.2 Operating Costs for SCR/Oxidation Catalyst Versus SCONO$_x$.

Table 3-5 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 2.0 ppmvd while firing natural gas for GEC Units 1 and 2 CCCTs. 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 1.1 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.

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.

3.6.7.3 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 3-5 shows the total annualized cost for a SCR/Oxidation Catalyst systems for each CCCT firing natural gas is estimated to be $1,952,000, which is approximately a third of the cost of a SCONO$_X$ system having a total annualized cost of $6,693,000.

3.6.7.4 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.

Table 3-5
NO_x/CO Combined Control Alternative Annualized Cost ($) for Each CCCT
(GEC Units 1 and 2)

	DLN	SCONOx ($)	SCR/OX Cat ($)	Remarks
Direct Annual Cost				Cost based on emissions in Table 3-3
Catalyst Replacement	N/A	1,116,000	615,000	Includes freight, installation, 3-yr capital recovery factor SCR catalyst (3-yr life), 6-yr capital recovery factor for OX cat (6-yr life), and 5-yr capital recovery factor for SCONOx (5-yr life).
Operation and Maintenance	N/A	68,000	39,000	See text for background information on this item
Maintenance Materials	N/A	48,000	23,000	
Reagent Feed	N/A	N/A	155,000	Assumes 1.1 stoichiometric ratio
Natural Gas Consumption	N/A	66,000	0	
Power Consumption	N/A	110,000	205,000	Includes injection blower and vaporization of ammonia
Lost Power Generation	N/A	2,191,000	272,000	Back pressure on combustion turbine. Includes seven days of lost power generation time for catalyst/system cleaning for SCONOX
Annual Distribution Check	N/A	116,000	40,000	Estimated as 0.5% of the total direct cost for SCONOX and 1% for SCR
Total Direct Annual Cost	**N/A**	**3,715,000**	**1,349,000**	
Indirect Annual Costs				
Overhead	N/A	41,000	23,000	60% of O&M Cost
Administrative Charges	N/A	638,000	139,000	2% of Installed Cost
Property Taxes	N/A	0	0	Not included
Insurance	N/A	319,000	69,000	1% of Installed Cost
Capital Recovery	N/A	1,980,000	372,000	Capital Recovery Excluding Catalyst
Total Indirect Annual Costs	**N/A**	**2,978,000**	**603,000**	
Total Annualized Cost	**N/A**	**6,693,000**	**1,952,000**	

3.7 Step 4-Evaluate Most Effective NO_X Controls

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 3.6.

3.7.1 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of a SCR to GEC Units 1 and 2 CCCTs 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 firing natural gas 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 base load for 8,760 hours per year on natural gas.

3.7.2 Economic Impacts for SCR (2.0 ppmvd NO_X) System

The use of an SCR has significant economic impacts to the JEA Project. The application of SCR on GEC Units 1 and 2 CCCTs 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 3.6.7 and will not be repeated.

3.7.2.1 Capital Costs for SCR (2.0 ppmvd NO_X).

Table 3-6 summarizes the economic capital cost for implementing SCR on each CCCT. 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 each CCCT controlling NO_x to 2.0 ppmvd is estimated to be $4,421,000.

3.7.2.2 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 3-7 shows the total annualized cost for SCR systems are estimated to be

$1,724,000. This annualized cost for the each CCCT SCR system results in a cost effectiveness of approximately $6,719 per ton of NO_x removed.

Table 3-6
NO_X Emission Control Alternative Capital Cost for GEC Units 1 and 2

	DLN	SCR ($)	Remarks
Direct Capital Cost			Cost based on emissions in Table 3-3.
Catalyst	N/A	1,102,000	Estimated from CERAM
Catalyst R. Housing /Ductwork	N/A	630,000	Estimated from Turner EnviroLogic
Control/Instrumentation	N/A	150,000	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	N/A	985,000	Estimated from Turner EnviroLogic
Purchased Equipment Costs (PEC)	**N/A**	**2,867,000**	
Sales Tax		0	Not applicable to JEA.
Freight	N/A	287,000	10% of PEC
Balance of Plant	N/A	860,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**4,014,000**	
Indirect Capital Costs			
Contingency	N/A	401,000	10% of DC
Engineering and Supervision	N/A	401,000	10% of DC
Construction & Field Expense	N/A	201,000	5% of DC
Construction Fee	N/A	401,000	10% of DC
Start-up Assistance	N/A	80,000	2% of DC
Performance Test	N/A	25,000	Assumed $25,000
Total Indirect Capital Costs (IC)	**Base**	**1,509,000**	
Installed Costs (DC + IC)		**5,523,000**	
Less SCR Catalyst Cost		1,102,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**Base**	**4,421,000**	

Table 3-7
NO_X Emissions Control Annualized Cost ($) for Each CCCT
(GEC Units 1 and 2)

	DLN	SCR ($)	Remarks
Direct Annual Cost			Cost based on emissions in Table 3-3
Catalyst Replacement	N/A	488,000	Includes freight, installation, and 3-yr capital recovery factor based on 3-yr guaranteed catalyst life
Operation and Maintenance	N/A	39,000	See text for background information
Maintenance Materials	N/A	23,000	See text for background information
Reagent Feed	N/A	155,000	Assumes 1.1 stoichiometric ratio
Power Consumption	N/A	205,000	Includes injection blowers and vaporization of ammonia
Lost Power Generation	N/A	272,000	Back pressure on combustion turbine
Annual Distribution Check	N/A	40,000	Estimated as 1 % of the total direct cost
Total Direct Annual Cost	N/A	1,222,000	
Indirect Annual Costs	N/A		
Overhead	N/A	23,000	60% of Operation and Maintenance cost
Administrative Charges	N/A	110,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	55,000	1% of Installed Costs
Capital Recovery	N/A	314,000	Capital recovery excluding catalyst
Total Indirect Annual Cost	N/A	502,000	
Total Annualized Cost	N/A	1,724,000	
NO_x Annual Emissions, tpy	318.4	61.8	Emission taken from Table 3-3
NO_x Emissions Reduction, tpy	N/A	256.6	Emissions calculated in Table 3-3
NO_x Total Cost Effectiveness, $/ton	N/A	6,719	Total Analyzed Cost/Emissions Reduction

3.8 Step 4-Evaluate Most Effective CO Controls

The following section identifies economic impacts of the CO 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 3.6.

3.8.1 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the JEA Project. An analysis of the economic impact is provided in this section. An analysis of the economic impact of oxidation catalyst as a separate control technology for CO emissions of 2.0 ppmvd firing natural gas 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 base load for 8,760 hours per year on natural gas.

3.8.2 Capital Cost for Oxidation Catalyst

Table 3-8 presents the capital costs for installing an oxidation catalyst on each CCCT during natural gas firing to achieve a CO outlet emission level of 2.0. 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 3.6.7.1.

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 each CCCT is estimated to be $822,000.

3.8.3 Operating Costs for Oxidation Catalyst

Table 3-9 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve a 74 percent reduction in CO emissions while firing natural

gas on each CCCT. Annualized operating costs for the system includes catalyst 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, however, it was assumed to be six years.

3.8.4 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. Firing natural gas, the total annualized cost for a 2.0 ppmvd CO oxidation catalyst systems for each CCCT are estimated to be $228,000. This annualized cost for each CCCT results in a cost effectiveness of approximately $2,161 per ton of CO removed.

Table 3-8
CO Reduction System Capital Cost ($) for Each CCCT
(GEC Units 1 and 2)

	Good Combustion Controls/DLN	Oxidation Catalyst ($)	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-3.
Oxidation Catalyst	N/A	615,000	Estimated from BASF
Catalyst Reactor Housing	N/A	75,000	
Control/Instrumentation	N/A	45,000	Estimated; includes controls and monitoring equipment.
Purchased Equipment Costs (PEC)	N/A	735,000	
Sales Tax	N/A	0	Not applicable to JEA
Freight	N/A	74,000	10% of PEC
Balance of Plant	N/A	221,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**1,030,000**	
Indirect Capital Costs	N/A		
Contingency	N/A	103,000	10% of DC
Engineering and Supervision	N/A	103,000	10% of DC
Construction & Field Expense	N/A	52,000	5% of DC
Construction Fee	N/A	103,000	10% of DC
Start-up Assistance	N/A	21,000	2% of DC
Performance Test	N/A	25,000	Assumed value of $25,000
Total Indirect Capital Costs (IC)	**Base**	**407,000**	
Installed Costs (DC +IC)		**1,437,000**	
Less Catalyst	N/A	615,000	Catalyst is viewed as an O&M Value.
Total Capital Investment, TCI	**Base**	**822,000**	

Table 3-9
CO Control Annualized Cost ($) for Each CCCT
(GEC Units 1 and 2)

	Good Combustion Controls/DLN	Oxidation Catalyst ($)	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1.
Catalyst Replacement	N/A	127,000	Includes freight, installation, and 6-yr capital recovery factor based on 6 yr guaranteed catalyst life.
Operation and Maintenance	N/A	0	Not applicable for Oxidation Catalyst
Lost Power Generation		0	Back pressure on combustion turbine
Total Direct Annual Cost	**N/A**	**127,000**	
Indirect Annual Costs			
Overhead	N/A	0	Not Applicable because of zero O&M
Administrative Charges	N/A	29,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	14,000	1% of Installed Costs
Capital Recovery	N/A	58,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**N/A**	**101,000**	
Total Annualized Cost	**Base**	**228,000**	
CO Annual Emissions, tpy	143.2	37.7	Emissions taken from Table 3-3.
CO Emissions Reduction, tpy	N/A	105.5	Emissions taken from Table 3-3.
CO Total Cost Effectiveness, $/ton	**N/A**	**2,161**	**Total Annualized Cost/Emissions Reduction**

Step 5-Select NO_X BACT

Based on the cost effectiveness value for the SCR catalyst it is determined that add-on controls to further reduce NO_X emissions are warranted. JEA has determined that the top NO_x control alternative when firing natural gas (primary fuel), Dry Low-NOX (DLN) Burners with SCR catalyst, represents NO_x BACT for GEC Units 1 and 2 CCCTs, corresponding to an emissions limit of 2 ppmvd at 15 percent O_2 on a 24 hour average basis. The top NO_x control alternative when firing ULSFO (backup fuel), Water Injection (WI) with SCR catalyst, represents NO_x BACT for the GEC Unit 1 and Unit 2, corresponding to an emissions limit of 8.0 ppmvd at 15 percent O_2 on a 24 hour average basis. Table 3-10 summarizes the Project's NO_x BACT determination for GEC Units 1 and 2.

Table 3-10
GEC Units 1 and 2 CCCTs NO_x BACT Determination

Control Technology	Emission Limit
DLN Burners with SCR (for natural gas combustion)	NG: 2.0 ppmvd @ 15% O_2 (24-hr avg.)
WI/SCR (for ULSFO combustion)	ULSFO: 8.0 ppmvd @ 15% O_2 (24-hr avg.)

3.9 Step 5-Select CO BACT

Based on the high cost effectiveness value for the oxidation catalyst it is determined that add-on controls to further reduce CO emissions are unwarranted given the low CO emission characteristics of GEC Units 1 and 2 CCCTs 4 firing natural gas as the primary fuel. As a basis for review, the cost-effectiveness guidelines are pollutant-specific, considering the control technology, environmental sensitivity, and determinations from similar BACT trends for that pollutant in the affected region and across the country. JEA believes that an oxidation catalyst is not BACT for this project. This determination is independent of the NO_X control determination. The CO BACT assessment is firmly based on the energy, environmental, and economic impacts detailed in the application, as well as recent Department determinations for similar units at similar emission levels. In those determinations, the Department has found that add-on controls to further reduce CO emissions are unwarranted given the already low emissions

characteristics of this particular gas turbine firing natural gas as the primary fuel. A few of those particular determinations are FPL Turkey Point, TECO Bayside Power Station, FMPA Treasure Coast, Progress Energy Hines Power Block 4, and most recently FMPA Cane Island Unit 4, which are all documented in Attachment 2. The CO BACT cost-effectiveness for JEA has determined that the CO BACT for GEC Units 1 and 2 CCCTs during natural gas firing with and without the operation of the natural gas fired duct burners at 100 percent load is good combustion controls. The CO BACT emission limit with and without duct burners operating is a stack test limit of 7.6 ppmvd at 15 percent O_2 and 4.1 ppmvd at 15 percent O_2, respectively. The top CO control alternative when firing ULSFO, good combustion controls, represents CO BACT for the GEC Units 1 and Unit 2 CCCTs, corresponding to an emissions limit of 8.0 ppmvd at 15 percent O_2 on a 24-hour block. The CEMS average limit firing natural gas or ULSFO is proposed as 8.0 ppmvd @ 15% O_2, and 24-hour block average. Table 3-11 summarizes the Project's CO BACT determination for GEC Units 1 and 2 CCCTs.

Table 3-11
GEC Units 1 and 2 CCCTs CO BACT Determination

Control Technology	Emission Limit
Good Combustion Controls	NG: 7.6 ppmvd @ 15% O_2 (stack test, 3-run average) with DBs; 4.1 ppmvd @ 15% O_2 (stack test, 3-run average) w/o DBs; ULSFO: 8.0 ppmvd @ 15% O_2 (stack test, 3-run average) NG or ULSFO: 8.0 ppmvd @ 15% O_2 (CEMS, 24-hour block average)

4.0 GEC Units 1 and 2 CCCTs PM/PM_{10} BACT Analysis

The objective of this analysis was to determine BACT for PM/PM_{10} emissions from GEC Units 1 and 2 CCCTs. 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 turbines are a result of incomplete combustion and trace particulate parameters in the fuel. The emissions of particulate matter from GEC Units 1 and 2 CCCTs 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. As for ULSFO, it contains small 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 West County, FMPA Treasure Coast, FPL Turkey Point, FPL Martin, FPL Manatee, FPL Fort Myers, FMPA Cane Island Unit 4, Santa Rosa and the City of Tallahassee projects, the use of combustion controls and natural gas as the primary fuel (ULSFO as backup) is considered BACT for particulate matter and is proposed for GEC Units 1 and 2 CCCTs.

5.0 GEC Units 1 and 2 CCCTs SO_2 BACT Analysis

The objective of this analysis was to determine BACT for SO_2 emissions from GEC Units 1 and 2 CCCTs.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. As for ULSFO, it has very low amounts of sulfur as well. The selection of natural gas fuel and ULSFO 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 simple cycle combustion turbines. Such a system would be both technically and economically prohibitive.

Therefore, BACT for GEC Units 1 and 2 CCCTs is the use of natural gas or ULSFO. The basis of this determination is firing natural gas and ULSFO on the limitation on hours of operation as previously stated.

6.0 GEC Units 1 and 2 CCCTs H_2SO_4 BACT Analysis

The objective of this analysis was to determine BACT for sulfuric acid mist (H_2SO_4) emissions from GEC Units 1 and 2 CCCTs. Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The natural gas and ULSFO to be utilized for GEC Units 1 and 2 CCCTs 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 ULSFO) 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 ULSFO fired combustion turbines by regulatory agencies.

Therefore, BACT for GEC Units 1 and 2 CCCTs is the use of good combustion controls while firing natural gas or ULSFO. The basis of this determination is firing natural gas and ULSFO on the limitation on hours of operation as previously stated.

7.0 GEC Units 1 and 2 CCCTs Cooling Tower

A new eight-cell linear mechanical draft cooling tower will be used to dissipate heat from the condensing water of the Project's steam turbine. Particulate from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as "drift" or moisture droplets that are suspended in the air moving out of the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate, leaving the suspended or dissolved solids in the atmosphere.

The particulate emissions from the cooling towers can be controlled by minimizing the amount of water drift that occurs and/or minimizing the amount of dissolved solids in the water. This can be accomplished by using high efficiency drift eliminators, a decreased number of cycles of circulating water concentration, or a combination of both. The number of cycles of water concentration is limited by the amount of water available for use, since lower levels of concentration require increased cooling tower blowdown and more water intake to offset the blowdown.

A review of drift eliminators as particulate control technology for cooling towers concluded that they are technically feasible. There are no significant energy, environmental, or economic impacts that would preclude the use of drift eliminators as particulate control technologies as presented in this evaluation.

The proposed cooling tower BACT for this Project is the use of drift eliminators for particulate control, with a cooling tower design drift rate of 0.0005 percent.

Attachment 1: NO_x Control Technology Review List

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	2.5 ppm (0.0092 lb/mmbtu)		SCR	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners – Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	12/01/2004	After 18 months, the 3-hour average changes to 1-hr average unless it is demonstrated it can not be met.	RBLC
Salt River Project – Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	2 ppm @ 15% O2	1-hr	SCR	03/07/2003		RBLC
Caithness Blythe II, LLC – Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	3-hr	SCR	04/25/2007		RBLC
Calpine Western Regional – Pastoria Energy Facility	CA	NG	750	3			2.5 ppm @ 15% O2	1-hr	DLN, SCR	12/23/2004		RBLC
Calpine Corp. – Sutter Power Plant	CA	NG	500	2			2 ppm @ 15% O2	1-hr	SCR	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	2.5 ppm @ 15% O2	1-hr	SCR	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	2 ppm @ 15% O2	1-hr	SCR	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	2.5 ppm @ 15% O2	1-hr	SCR	03/01/2003		CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	SCR	5/7/2003		CARB BACT Clearinghouse
Calpine Corp. – Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2	1-hr	DLN, SCR	05/02/2006	NO_X Limited To Max of 100 PPM @ 15% O2 during startup and shutdown.	RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	3.5 ppm NG; 15 ppm FO	3-hr	SCR	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	3.5 ppm	24-hr	SCR	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	2.5 ppm NG; 10 ppm FO	24-hr	SCR	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	09/19/2003	SCONOx - $8,597/ton NOx;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	2.0 ppm NG/8.0 ppm FO	24-hr	SCR	02/08/2005	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	05/30/2006	180 km from the Everglades National Park	RBLC
Orlando Utilities Commission -- Curtis H. Stanton Energy Center, Unit B	FL	NG; FO	285	1	1	GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	Application under Review		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsbishi M501G	2.0 ppm NG (CT/CT and DB); 8.0 ppm FO	24-hr block	SCR	01/10/2007	SCR - $3,385/ton NO_X	FDEP NSR/PSD Permits
FMPA Cane Island Unit 4	FL	NG	300	1	1	GE 7FA	2.0 ppm @ 15% O2	24-hr block	SCR	Draft Permit -- 5/8/2008	SCR - $4,250/ton NO_X	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.5 ppm		SCR	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 6 ppm FO		SCR	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	3.5 ppm		SCR	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	3.0 ppm NG; 8.0 ppm FO		SCR/DLN; WI	applic. under review	SCR - $5,075/ton NOx; CatOx - $4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-3 ppm	3-hour	SC-DLN; CC-SCR	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA,1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 42 ppm (oil); CC-3 ppm (NG), 33 ppm (oil)	3-hour	SC-DLN, CC-SCR	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	Steam Injection	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	3.5 ppm		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	4.5 ppm	24-hour	SCR, DLN	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Cresent City Power, LLC – Cresent City Power	LA	NG	600	2	2		3 ppm	Annual	DLN, SCR	06/06/2005	Startup emissions is limited to 220 lbs/hr; Project-wide emissions is limited to 74.33 tpy.	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	3.5 ppm		SCR	06/24/2002	SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	3.5 ppm @ 15% O2	3-hr	SCR	11/23/2004	Limits apply at all times.	RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2.5 ppm @ 15% O2	24-hr	DLN, SCR	04/13/2005	Project-wide emissions is limited to 239.4 tpy.	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	3.5 ppm	3-hr	SCR	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
El Dorado Energy, LLC	NV	NG	475	2	2		3.5 ppm @ 15% O2 (w/o DBs); 3.7 ppm @ 15% O2 (w DBs)		DLN, SCR	08/19/2004		RBLC
Sierra Pacific Power Company – Tracy Substation Expansion Project	NV	NG	612	2	2		2 ppm @ 15% O2	3-hr	SCR w/Ammonia Inj.	08/16/2005		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	2.5 ppm NG; 9 ppm FO	1 hour	DLN/SCR	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA		1 hour		09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	2.5/3.5 ppm		SCR	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246/ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	2.5/3.5 ppm	24-hr block	SCR	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	3.5 ppm		SCR	applic. under review	SCONOx - $22,600/ton NOx; CatOx - $3,560/ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	3.5 ppm; 15 ppm FO		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC – Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 (first 500 hours); 3 ppmdv @ 15% O2 (after 500 hours)	24-hr	DLN, SCR	09/29/2005	The use of fuel oil is limited to 1,200 hours per year and only during the months of November through March.	RBLC/EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC – Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	3 ppm @ 15% O2	3-hr	DLN, SCR	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

NO_X Top Down RBLC Clearinghouse Review Results
Table A-1

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	2.0 ppmdv @ 15% O2	3-hr	DLN, SCR	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			DLN, SCR	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			DLN, SCR	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Hillsatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class			DLN, SCR	Drafting	Lane County, OR.	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. – Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	08/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 7.5 ppm FO	24-hr	SCR	05/28/2002	SCONOx - $19,470/ton NOx; CalOx - $3,420/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	3.5 ppm	24-hr	SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	3.5 ppm		SCR	applic. under review	SCONOx - $18,785/ton NOx; CalOx - $2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE F7B	3.5 ppm NG; 42 ppm FO		DLN/SCR; WI	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	5		SCR	07/23/2003		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	5 ppm		SCR	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	9.0 ppm SC; 2.25 ppm CC; 25 ppm (transient load conditions)	1-HR SC; 3-hr CC; ERR	DLN - SC; SCR - CC	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard -- Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	2 ppm @ 15% O2	3-hr	SCR	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	3.0 ppm		SCR	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	1-hr	DLN, SCR	06/05/2007		RBLC
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	2.5 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA; NOC 8695	NG; FO	280	1	0	GE Frame 7FA	2.5 / 6 ppmdv gas / oil @ 15% O2	1-hr	DLN, SCR	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.5 ppmdv @ 15% O2	Annual	DLN, SCR	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.5 ppmdv @ 15% O2	3-hr	DLN, SCR	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC – BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2.5 ppm @ 15% O2	3-hr	DLN, SCR	01/11/2005		RBLC

Color Code Legend
Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet
Data from EPA's RBLC Clearinghouse
Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website -- Power Plants
Data from CARB's BACT Clearinghouse

Attachment 2: CO Control Technology Review List

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB		GCP	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners -- Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	12/01/2004		RBLC
Salt River Project -- Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	03/07/2003		RBLC
Carthness Blythe II, LLC -- Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	4.0 ppmdv @ 15% O2	3-hr		04/25/2007		RBLC
Calpine Corp. -- Sutter Power Plant	CA	NG	500	2			4 ppm @ 15% O2	3-hr	CatOx	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	4 ppm @ 15% O2	3-hr	CatOx	03/01/2003	CO limit was offered by catalyst vendor	CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	CatOx	5/7/2003	CO limit was proposed by the applicant	CARB BACT Clearinghouse
Calpine Corp. -- Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2		GCP, CatOx	05/02/2006		RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	14 ppm	24-hr	GCP	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	9 ppm (7.8 ppm test avg.)	24-hr	GCP	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	8 ppm NG (15 ppm w/PA) ; 17/19/26 ppm FO	24-hr	GCP	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	10 ppm NG/20 ppm FO	24-hr	GCP	09/19/2003	SCONOx - $8,597/ton NOx;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PA&DB; 8.0 ppm FO/ 8.6.0 ppm (12-month avg.)All modes	24-hr/12-mo	GCP	02/08/2005	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	8 ppm @ 15% O2 NG; 12 ppm FO	24-hr	GCP	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	6 ppm (12-month); 8 ppm FO (24-hr); 4.1 ppm NG w/o DBs (24-hr)	12-month or 24-hr	GCP	05/30/2006	Continuous compliance with ppm limit by CEMS	RBLC
Progress Energy -- P.L. Bartow Power Plant	FL	NG; FO	1,475	4	4	Siemens SGT6-5000F	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	Draft Permit	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.); Cat. Ox. - $3,956/ton CO	FDEP NSR/PSD Permits
Orlando Utilities Commission -- Curtis H Stanton Energy Center, Unit B	FL	NG, Syn. Gas	285	1	1	GE 7FA	Syn. Gas or NG: 4.1 ppm @ 15% O2 (between 21 and 27 months following the initial compliance tests)	24-hr rolling avg	CatOx	12/22/2006		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsbishi M501G	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	01/10/2007	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.)	FDEP NSR/PSD Permits
FMPA Cane Island Unit 4	FL	NG	300	1	1	GE 7FA	7.6 ppm @ 15% O2 with DBs; 4.1 ppm @ 15% O2 w/o DBs	3-hr Stack Test	GCP	Draft Permit -- 5/8/2008	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.)	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.0 ppm		CatOx	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,280	4	4	GE 7FA (170 MW)	2.5 ppm		CatOx	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	10 ppm (17 ppm w/DB or PA)		GCP	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	19.2 ppm (w/DB)/9.0 ppm (w/o DB); NG; 25.6 ppm FO		GCP	applic. under review	SCR - $5,075/ton NOx; CatOx - $4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-5 ppm	3-hour	Oxidation Catalyst	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA, 1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 20 ppm (oil); CC-5 ppm (NG), 7.1 ppm (oil)	3-hour	Oxidation Catalyst	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	GCP	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	9/13.9/20 ppm		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	16.9 ppm	short-term	GCP	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Cresent City Power, LLC -- Cresent City Power	LA	NG	600	2	2		4 ppm @ 15% O2	Annual	GCP, CatOx	06/06/2005	Startup emissions is limited to 1,530 lbs/hr. Project-wide emissions is limited to 567.11 tpy.	RBLC
Nothernern States Power Co. DBA XCEL Energy – Riverside Plant	MN	NG	528	2	0	GE 7FA (170 MW)	10.0 ppmdv @ 15% O2	3-hr	GCP	05/16/2006	Three existing coal-fired boilers being replaced by 2 GE 7FA CCCTs; CatOx rejected at $7,670/ton of CO	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	10.4 ppm		GCP	06/24/2002	SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	18.36 ppmv @ 15% O2	3-hr	GCP	11/23/2004		RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2 ppm @ 15% O2	3-hr	CatOx	04/13/2005	All 3 turbines and duct burners combined are limited to 165.5 tpy	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	10.8 lb/hr	Stack	CatOx	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
Sierra Pacific Power Company – Tracy Substation Expansion Project	NV	NG	612	2	2		0.03 lb/Mbtu	3-hr	GCP	08/16/2005		RBLC
El Dorado Energy, LLC	NV	NG	475	2	2		2.6 ppm @ 15% O2 (each CTG); 3.5 ppm @ 15% O2 (CTG + DB)		CatOx	06/19/2004		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	4 ppm	1 hour	CatOx	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA				09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	9 ppm (14 ppm w/DB)		GCP	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level. SCONOx - $21,542/ton NOx; CatOx - $3,246/ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	15 or 30 ppm	24-hr block	GCP	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	9 ppm (24.3 ppm w/DB)		GCP	applic. under review	SCONOx - $22,600/ton NOx; CatOx - $3,560/ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	9 ppm NG (20 ppm w/DB) 20 ppm FO		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC -- Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	11.6 ppm NG (25.6 ppm w/DB); 15.7 ppm FO (25.1 ppm w/DB)	3-hr	GCP	01/23/2004	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels	EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC -- Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	9 ppm @ 15% O2	24-hr	GCP	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine. Each turbine has a limit of 278 tpy of CO.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	4.9 ppmdv @ 15% O2	3-hr	CatOx	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results
Table A-2

FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	6.0 ppmdv @ 15% O2	24-hr	CatOx	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			CatOx	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	5.0 ppmdv @ 15% O2	8-hr	CatOx	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region Bonanza, OR	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	5.0 ppmdv @ 15% O2	8-hr	CatOx	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			CatOx	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class				Drafting	Lane County, OR	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. -- Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	CatOx	06/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)		GCP	05/28/2002	SCONOx - $19,870/ton NOx; CatOx - $3,330/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	14 ppm (GE7FA)/16 ppm (SW501F)	24-hr	GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	15 ppm (31 ppm w/DB)		GCP	applic. under review	SCONOx - $18,780/ton NOx; CatOx - $2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE F7B	varies from 7.4 to 50 ppm depending on CT type and load		GCP	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	15 ppm		GCP	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	20			07/23/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	7.8 ppm SC, 3.0 ppm CC	24-hR SC, 3-hr CC; ERR	Oxid Cat	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard – Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	3 ppm @ 15% O2	3-hr	CatOx	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	21 ppm		GCP	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	9 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 with Power Augmentation and DBs		CatOx and GCP	06/05/2007	CO Limit: 1.3 ppmvd @15% O2 w/o Power Aug., 1.8 ppmvd @ 15% O2 w/Power Aug and w/o DBs	RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA NOC 8695	NG; FO	280	1	0	GE Frame 7FA	2.0 / 3.0 ppmdv @ 15% O2	1-hr	CatOx	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.0 ppmdv @ 15% O2	Ann	CatOx	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.0 ppmdv @ 15% O2	3-hr	CatOx	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC – BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2 ppm @ 15% O2	3-hr	GCP, CatOx	01/11/2005		RBLC

Color Code Legend

Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet

Data from EPA's RBLC Clearinghouse

Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website – Power Plants

Data from CARB's BACT Clearinghouse

Appendix E
Air Dispersion Modeling Protocol

JEA - Greenland Energy Center
Units 1 and 2
Combined Cycle Conversion

Air Dispersion Modeling Protocol

JULY 2008

Prepared for:
JEA
Jacksonville, Florida

Prepared by:
Black & Veatch
Overland Park, Kansas

BLACK & VEATCH
Building a world of difference.

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1.0 Introduction

JEA is proposing to convert the two simple cycle combustion turbines (CTs) at the Greenland Energy Center (GEC) into a 2 x 1 combined cycle configuration. The GEC is located in southeastern Duval County, Florida and is currently undergoing construction permitting for the two simple cycle units. The combined cycle configuration will consist of the same two General Electric (GE) 7FA combustion turbines that are currently being permitted as simple cycle units, but will now each include a heat recovery steam generator with supplemental natural gas-fired duct burners exhausting to one steam turbine generator (Unit 3). The simple cycle functionality of each combustion turbine will be retained post-combined cycle conversion. The currently proposed simple cycle combustion turbine stack will function as a bypass stack when the combustion turbines are operating in a simple cycle mode. The proposed conversion Project will include only the combined cycle conversion of the simple cycle units, with no further additions to the ancillary units already included as part of the simple cycle operations. However, these ancillary units will be included in the modeling demonstration for the combined cycle conversion.

Florida Department of Environmental Protection (FDEP) has requested that JEA submit the air permit application for the combined cycle conversion as if the Project were initially planned for and designed as a combined cycle facility rather than as a modification to the simple cycle facility with associated increases in emissions. To that end, JEA anticipates that the potential emissions of the combined cycle conversion will trigger air permitting review requirements under the Prevention of Significant Deterioration (PSD) program of Florida Regulation 62-212.400.

A modeling protocol for the simple cycle configuration was previously approved by FDEP in February 2008 and is similar in methodology to that proposed herein. This Air Dispersion Modeling Protocol (hereinafter referred to as the Protocol) describes the air quality impact analysis methodology for obtaining a Construction Permit for the proposed combined cycle conversion Project under the PSD review program. Simple cycle operational modes to be considered along with the combined cycle modes will be modeled in accordance with the already approved modeling protocol for the simple cycle operations. After FDEP review and approval, this Protocol will provide the basis of a mutually agreed upon procedure for the final ambient air quality impact analysis in support of the air construction permit application meeting PSD review requirements.

This Protocol describes site and source characteristics, determination of pollutants applicable to the air quality review, and the analytical procedures that will be used to conduct the ambient air quality impact analysis (AAQIA). The construction permit application and supporting AAQIA will include a determination of compliance with the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards (NSPS), the PSD increments, and an assessment of additional impacts.

2.0 Project Characterization

The following sections briefly characterize the Project including a general description of the facility, location, and potential emission units.

2.1 Project Location

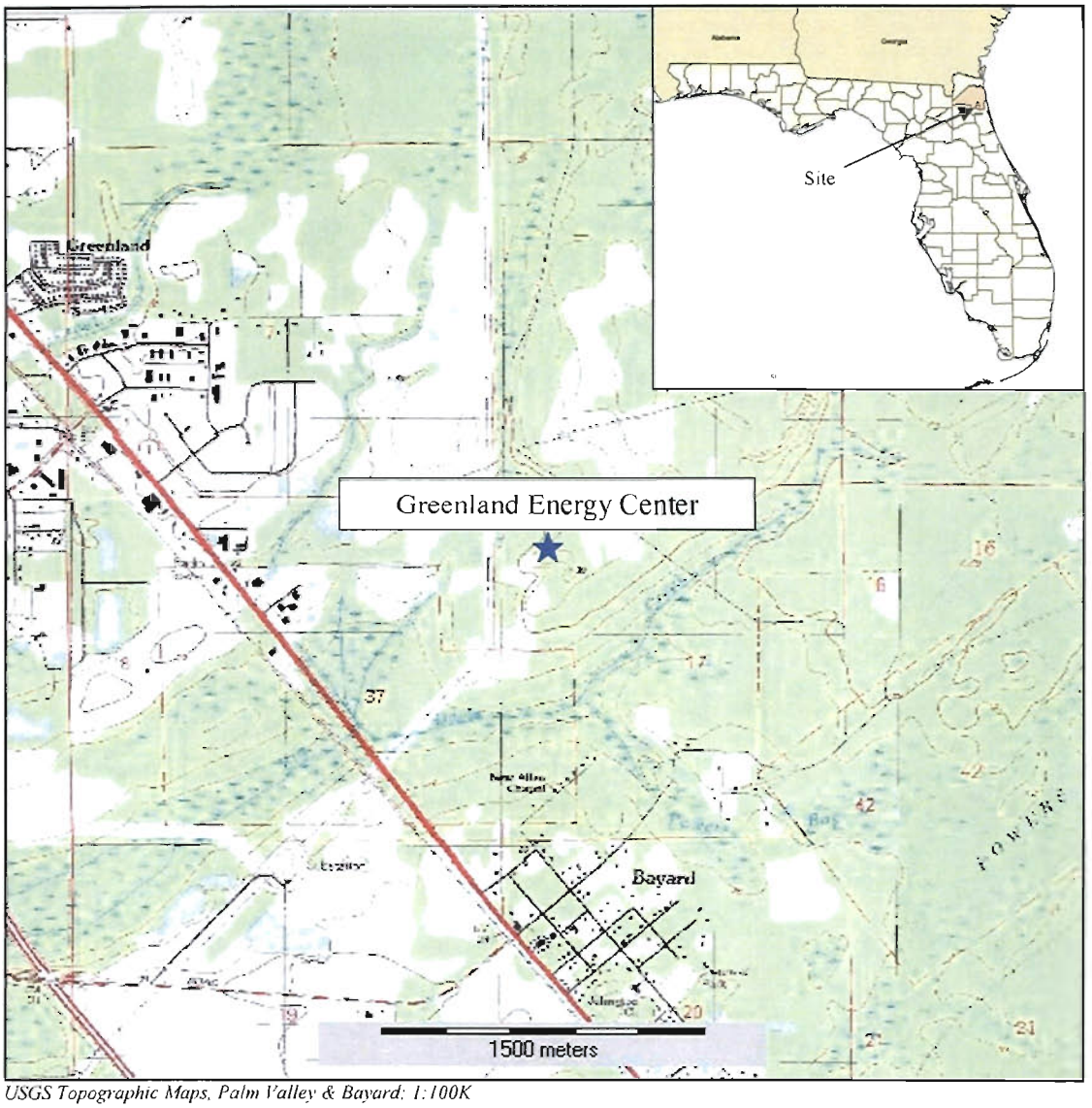
The GEC is located in southeastern Jacksonville. The specific location of the Project is illustrated in Figure 2-1. The site location has a sub-tropical climate with hot summers and mild winters.

2.2 Project Description

JEA is proposing to convert the two simple cycle CTs at the GEC into a 2 x 1 combined cycle configuration. The combined cycle configuration will consist of the same two GE 7FA combustion turbines that are currently being permitted as simple cycle units, but will now each include a heat recovery steam generator with supplemental natural gas-fired duct burners exhausting to one steam turbine generator (Unit 3). The simple cycle functionality of each combustion turbine will be retained post-combined cycle conversion. Each of the currently proposed simple cycle combustion turbine stacks will function as a bypass stack when the combustion turbines are operating in a simple cycle mode. The proposed combined cycle block will generate a nominal 547 MW net (563 MW gross) when firing natural gas and 524 MW net (541 MW gross) when firing ultra low sulfur fuel oil (ULSFO).

2.3 Project Emissions

For the proposed combined cycle combustion turbine (CCCT) operation, emissions and stack parameters will be developed from performance data for unit loads of 100, 75, and 50 percent of maximum capacity over a range of representative ambient temperatures (7, 59, 69, and 105°F) for both natural gas and ultra low sulfur fuel oil firing. This range of temperatures represents the site minimum, ISO, site average, and site maximum temperatures, respectively. The emissions included in the air dispersion modeling analysis for combined cycle operation will be based on direct pound per hour emissions to the atmosphere.



USGS Topographic Maps, Palm Valley & Bayard; 1:100K

Figure 2-1
Proposed Project Location

The combined cycle units will have the capability of operating in several configurations; including firing natural gas or ULSFO, along with the various unit loads across a range of ambient temperatures. Because of the numerous operating scenarios and configurations, a process called enveloping may be used in the modeling. Enveloping allows multiple operating scenarios to be conservatively considered in an AAQIA, while keeping the actual air dispersion modeling runs to a minimum. However, it is possible that because of the specific characteristics of the source, this analysis approach could result in overly conservative modeling impacts. In this case, the AAQIA may be performed for each individual load and ambient temperature combination.

As previously mentioned, the CT units will also be able to operate in simple cycle operation with the by-pass stacks. While the operating scenarios presented in the PSD application for simple cycle operation will remain unchanged, these scenarios may be combined with the proposed combined cycle operating scenarios as necessary to represent a number of potential operating scenarios where both modes of operation occur within a single modeled pollutant averaging period.

The emissions and stack parameters for each of the ancillary equipment will be based on manufacturer data and these emission sources will be included in the AAQIA. These sources and data will be the same as those included in the PSD air permit application modeling for the simple cycle combustion turbines, which was submitted to the FDEP in April 2008.

3.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for combined cycle operation at the GEC site, analyses of the proposed Project's effect on all Class I areas within 300 km will be performed. The Bradwell Bay Wilderness (BBW), Chassahowitzka Wilderness (CW), Okefenokee Wilderness (OW), St. Marks Wilderness (SMW), and Wolf Island Wilderness (WIW) areas are the Class I areas within this radius. 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 3-1 presents the location of the Project site with respect to the Class I areas.

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 BBW, CW, OW, SMW, and WIW.

3.1 Class I Model Selection and Inputs

3.1.1 Model Selection

The California Puff (CALPUFF, Version 5.8, Level 070623) air modeling system will be used to model the proposed Project and assess the AQRVs at the Class I areas. 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 (Version 5.8, Level 070623), 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. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech

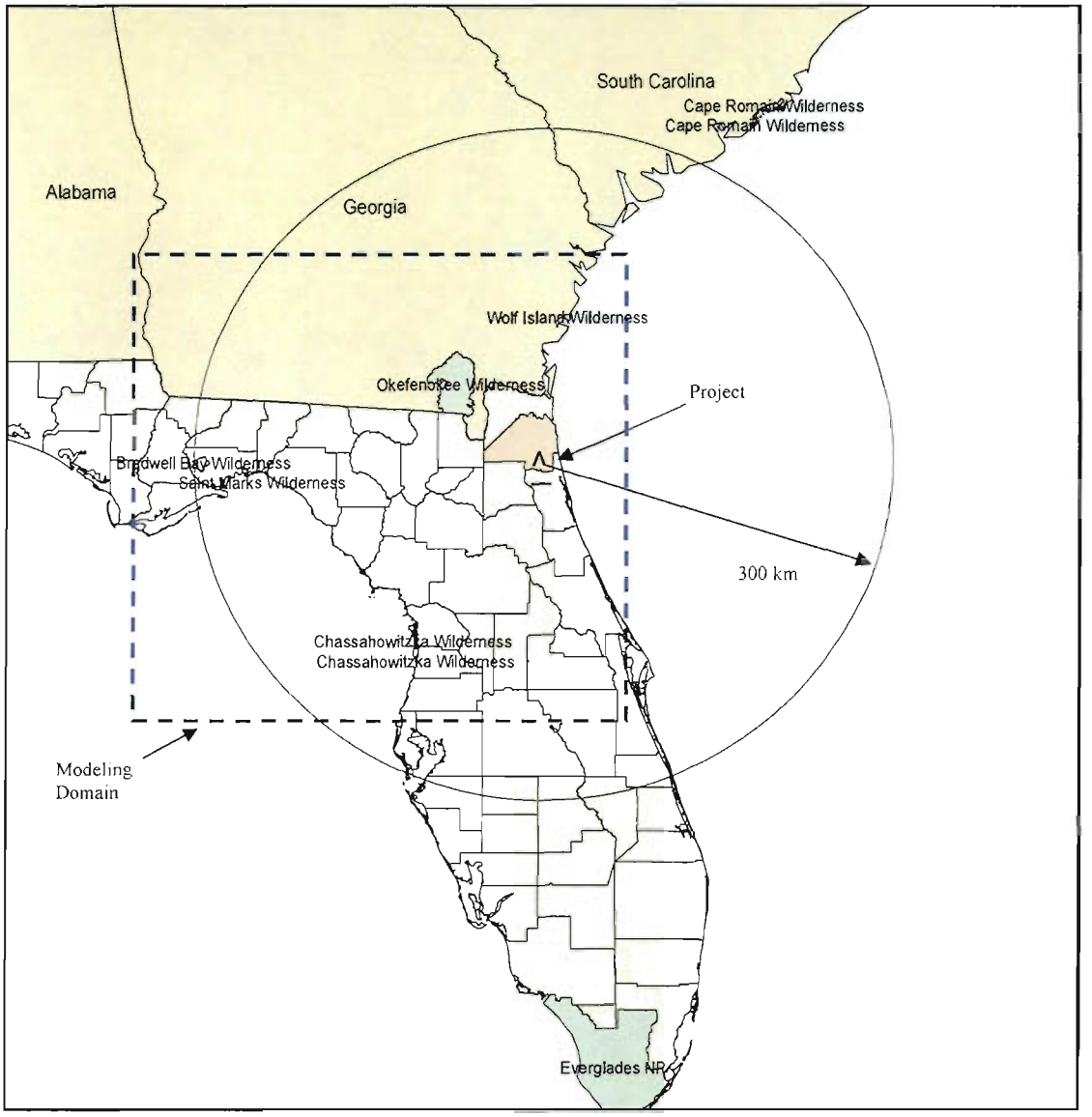


Figure 3-1
Proposed Project Location and Class I Areas

to produce CALPUFF-ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor for this modeling analysis. VISTAS has provided 2001-2003 CALMET files for five 4-km sub-regional domains as illustrated in Figure 3-2. The modeling proposed in this protocol will use the CALMET files prepared for sub-domain 2.

3.1.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 3-1 will be used for the modeling analyses.

3.1.3 Project Emissions

The CALPUFF analysis will include the emissions from the combined cycle units. The worst-case representative stack parameters and pollutants emission rates at 100 percent operating load on natural gas and ULSFO will be used in the CALPUFF analyses. Per guidance from NPS, the PM/PM_{10} emissions will be speciated based on size and composition and therefore be broken into the following constituents: elemental carbon (EC), organic carbon (OC), and soils (SOIL) for the regional haze analysis.

3.1.4 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 source. Dimensions for all significant building structures will be processed with the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274).

3.1.5 Receptor Locations

The CALPUFF analyses will use an array of discrete receptors over the Class I areas, which were created and distributed by the National Park Service (NPS). Specifically, the array consists of receptors appropriately spaced to cover the extent of the Class I areas. Receptor elevations are included in the same NPS- provided receptor files.

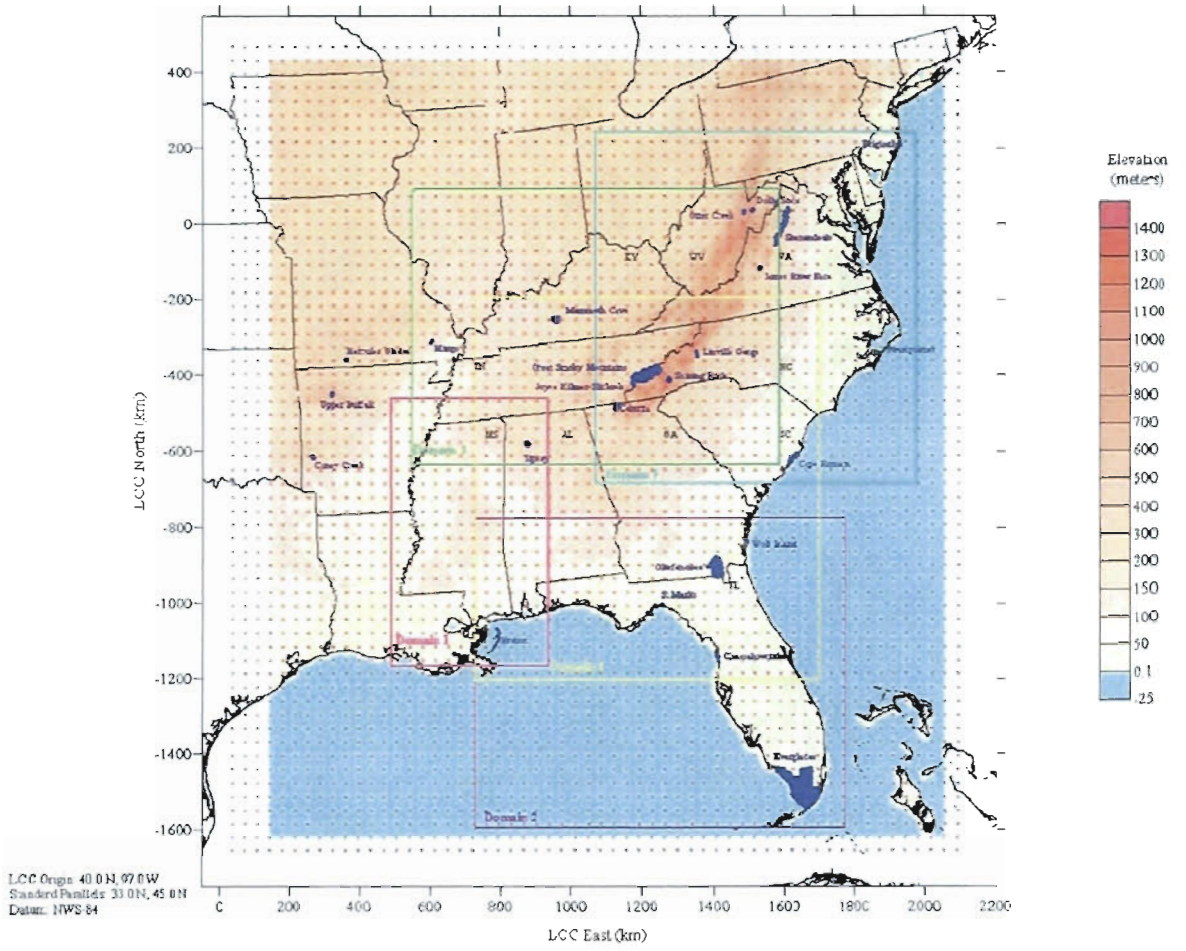


Figure 3-2
VISTAS 4-km CALMET Sub-Domains

Table 3-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species Emitted	SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	VISTAS CALMET Files
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME 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 Class I SILS: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Rates (SERs).
Background Values	Ammonia: 0.5 ppb (monthly); Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. A review of the CASTNET database will be performed to obtain monthly averages and these values will be substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

3.1.6 Meteorological Data Processing

The refined 4-km grid resolution VISTAS CALMET files from sub-domain 2 will be used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution MM5 data available for each year (i.e., 12-km MM5 data for 2001 and 2002 and 36-km MM5 data for 2003). A 4-km grid resolution is expected to be adequate given the lack of significant terrain features in central Florida

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish & Wildlife Service (FWS) using the current EPA regulatory version of CALMET, i.e., Version 5.8 Level 070623. Black & Veatch obtained this re-processed fine-grid CALMET dataset for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

3.1.6.1 CALMET Settings

The major features of CALMET used by Earth Tech to develop the CALMET files are listed below.

- Modeling period: 3 years (2001-2003)
- Meteorological inputs: MM5 data provide initial guess fields in CALMET. Meteorological observational data are used in the Step 2 calculations. Overwater (buoy) data were used in addition to the hourly surface meteorological observations, precipitation observations and twice-daily upper air sounding data.
- CALMET grid resolution: 4-km
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: Refined mode with all available observational data included in the Step 2.
- Diagnostic options: IWAQM default values.
- CALMET options dealing with radius of influence parameters: R1 = 5 km, R2 = 5 km, RMAX1 = 40 km, RMAX2 = 40 km, RMAX3 = 100 km, BIAS(NZ) = 10*0, ICALM = 0.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments which was used for all years for the subregional domains. Value of 15 km was determined from testing and used in modeling.

- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter for the subregional simulations determined by TRC based on sensitivity tests was MNMDAV=1.
- Geophysical data for regional runs: 3 arc-second USGS DEM terrain data set (SRTM30 data also used as a backup in case when 3 arc-second data are missing), CTG USGS 200m land use dataset.
- References for these and other CALMET datasets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

3.1.7 Modeling Domain

The CALPUFF modeling domain will be a subset of the previously discussed CALMET 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 Class I areas with at least a 50 km buffer zone in each direction. The modeling analysis will be performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40 and 97 degrees, respectively. A rectangular modeling domain extending 412 km in the east-west (x) direction and 432 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is located at 1,137.995 km Easting and -1,206 km Northing (LCC, NWS-1984 coordinates). The grid resolution for the domain will be 4 km. A grid spacing of 4 km yields 103 grid cells in the x-direction and 108 grid cells in the y-direction. Figure 3-1 illustrates the size and location of the modeling domain.

3.2 CALPUFF Analyses

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

3.2.1 Regional Haze Analysis

A regional haze analysis will be performed for the Class I areas, for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model

predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions will be speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

3.2.1.1 Visibility

Visibility is an AQRV for all Class I areas except BBW, as such, a visibility analysis will not be performed for BBW. 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 Class I areas 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:

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

3.2.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the Class I areas. The background visual range, or constituents thereof, for each of the Class I areas 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 hour's relative humidity can 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 hour of relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). Alternately, the Phase I FLAG report provides seasonal relative humidity factors for each Class I area for direct input to the modeling process when using Method 6 as proposed herein.

3.2.1.3 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*, (EPA, 12/98) where appropriate. Table 3-2 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-2 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to 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 first 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. The relative humidity will be capped at 95 percent.

Then, as discussed with the FDEP on April 2, 2008, for the SCCT portion of the Project; regional haze impacts will be calculated using Method 6. Method 6 is similar to Method 2 except that seasonally averaged relative humidity adjustments are used to compute the resultant extinctions. Method 6 is the preferred method for performing regional haze analyses by all of the regional planning organizations across the country (including VISTAS which covers the Southeastern states and is the origin of the meteorological database used in these analyses). Additionally, Method 6 is recommended by the USEPA's BART Guidance (70 FR 39162) as the accepted post-processing option. However, unlike the BART guidance and analyses, the results presented in the application will be conservatively based on the highest maximum model-predicted impacts rather than the 98th percentile impact (i.e., the 8th high impact). 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.

Table 3-2
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 value; compute a day-average relative humidity factor (f(RH)) for the worst day for the predicted specie, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate.
Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98)	

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM speciation (EC & OC) 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:
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = 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
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 ($\mu g/m^3$) = 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
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   b_{exts} = 3[NH_4NO_3]f(RH) + 3[$(NH_4)_2SO_4$]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]
5. 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)
6. 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 speciated PM 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.

3.2.2 Deposition Analyses

Deposition analyses will be performed for all applicable Class I areas 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 3.1 (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).

3.2.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) at each of the Class I areas will be calculated for the appropriate criteria pollutants subject to PSD 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 Class I area 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.

4.0 Class II Ambient Air Quality Analysis

Air Dispersion Model:	AERMOD (Latest version)
Model Options:	USEPA recommended regulatory default options.
GEP & Downwash:	USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274) will be used to determine GEP stack height and direction specific building downwash parameters for each 10-degree azimuth direction for each stack. Structures associated with the new site will be included in the downwash 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 50 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Terrain Considerations:	Terrain elevations at receptors will be obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10% elevation slope from any given receptor. A visual inspection of the surrounding DEM files will be performed to ensure all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations will be determined using a method that interpolates the terrain elevation near each receptor.
Dispersion Coefficients:	A key feature of AERMOD's formulation is the use of directly observed variables of the boundary layer to parameterize dispersion; therefore, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of

assigning specific sources to have an urban effect, thus enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area. Since the proposed Project is not located in an urbanized area, urban boundary layer option will not be invoked.

Meteorological Data: Sequential hourly meteorological data will consist of Jacksonville surface and upper air data for the data period of 2001-2005. This data set is provided by and processed by Florida Department of Environmental Protection (FDEP) and is AERMOD ready.

Pollutants to be Modeled: The pollutants that are currently expected to be modeled are PM/PM_{10}, NO_x, SO_2, and CO.

Source Modeling Parameters: Representative combined cycle combustion turbine performance and emissions data for the several operating configurations; including natural gas or ultra low sulfur fuel oil firing. The performance and emission data will be determined across 50, 75, and 100 percent load cases at ambient temperatures of 7, 59, 69, and 105 °F. Enveloping may be used to determine the worst-case hourly emission rates and operating parameters for each load case across ambient temperatures and operating scenarios that will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average ambient temperature data, at 100 percent load.

Significant Impact Area: It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. However, if the predicted impact of one or more pollutants and applicable averaging periods are greater than the PSD SILs, then a significant impact area (SIA) will be determined and interactive cumulative source modeling will be performed for those pollutants to determine compliance with PSD increment limits. In this event, the proposed Project will develop a methodology for compiling a cumulative source inventory and submit to the agency that methodology for approval.

Preconstruction Monitoring: It is anticipated that the maximum model predicted pollutant impacts will be less than the applicable PSD significant monitoring concentrations, as such, an exemption from pre-application monitoring requirements is

requested. However, in the event the maximum model predicted impacts exceed the applicable PSD significant monitoring concentration for a given pollutant, then the existing ambient air quality monitoring network will be evaluated for representativeness of these data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for that pollutant.

It is anticipated that the NO_x emissions will be greater than 100 tpy; therefore, ozone will be subject to the PSD requirements. The existing ambient air quality monitoring network will be evaluated for representativeness of the ozone data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for ozone.

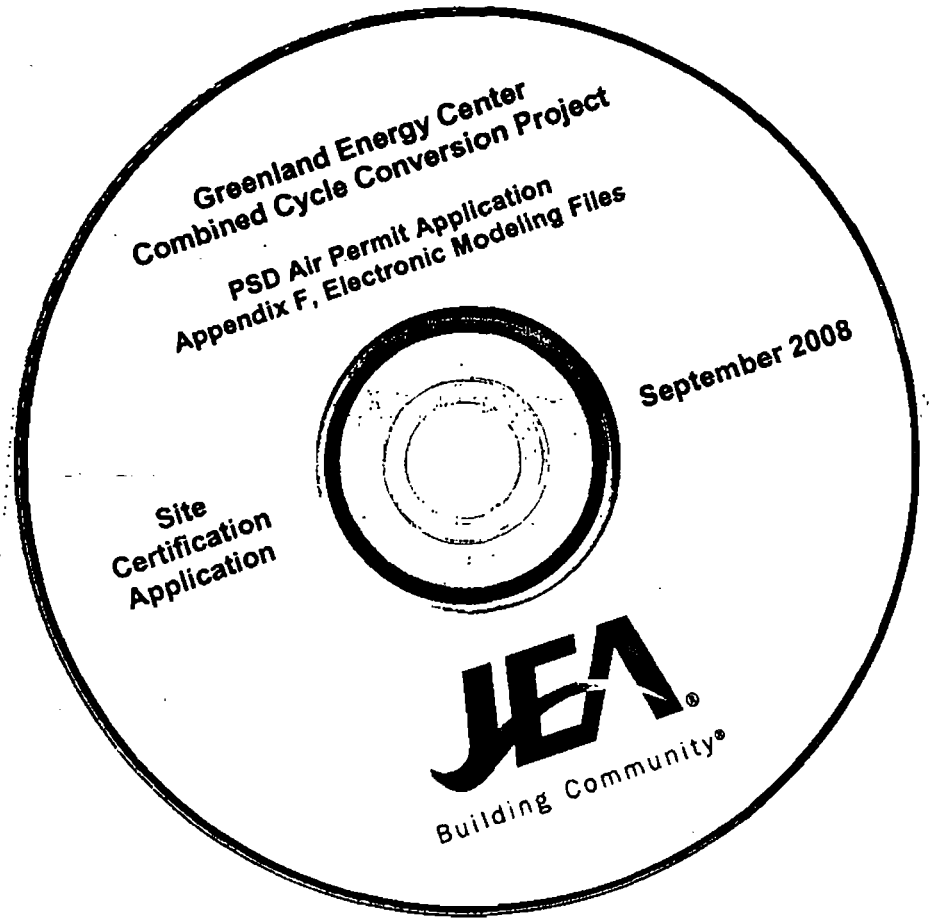
Additional Impacts: An analysis considering the impairment to soils and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source will be performed. The USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals* will serve as a basis for assessing the vegetation and soil impacts.

Toxics: No toxic modeling analysis is required.

Appendix F
Electronic Modeling Files

Appendix F - Electronic Modeling Files

A DVD of PSD Air Permit modeling files is in selected copies only, and is available upon request.


Greenland Energy Center
Combined Cycle Conversion Project
PSD Air Permit Application
Appendix F, Electronic Modeling Files
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Site
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