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BUREAU OF AIR REGULATION

JEA Brandy Branch

Combined Cycle Conversion

Site Certification Application

Appendix 10.7 – PSD Application

Manual Number JEA/BB - 007

Issued to Clair Fancy

Location ______

21 West Church Street

Jacksonville, Florida 32202-3139

JEA

December 8, 2000

Mr. Hamilton S. Oven
Administrator
Siting Coordination Office
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: JEA
Site Certification Application
Brandy Branch Combined Cycle Conversion

Dear Mr. Oven:

JEA is pleased to submit this Site Certification Application under the Florida Electrical Power Plant Siting Act for conversion of the Brandy Branch Generating Station to combined cycle operation. Units 1-3 are simple cycle combustion turbine units currently under construction at the site, 15 miles west of Jacksonville in Duval County, near Baldwin. Units 2 and 3 are proposed for conversion to combined cycle operation. All units, whether operating in simple or combined cycle mode, will fire natural gas as the primary fuel. Certification is sought for all units and associated facilities onsite, and the access road corridor.

Five copies of the application and a $125,000 check for the filing fee are enclosed for the Department's initial completeness review, as requested by Steven Palmer of your office. Additional copies will be submitted to you and distributed to the other agencies after the application is determined to be complete.

In addition, by copy of this letter, we are also submitting one signed and sealed original and three copies of the Prevention of Significant Deterioration permit application to the Department's Bureau of Air Regulation. This PSD application comprises Volume 3 of the Site Certification Application. The appropriate application fee for that permit modification is to be covered by the site certification application fee.

A petition to determine the need for the combined cycle unit was filed with the Public Service Commission on November 15, 2000. A copy of the Need for Power petition is included in Section 1 of the application.

We look forward to working with you and your staff as this application progresses through the certification process. If you have any questions, please do not hesitate to call me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

Enclosures

Cc: Clair Fancy, Chief , FDEP BAR (w/encls.)

Appendix 10.7

PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION FOR THE BRANDY BRANCH COMBINED CYCLE FACILITY

Submitted by

JEA

Prepared by

Black & Veatch

December 2000

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10.7 PSD Application

1.0 Introduction

JEA proposes to convert two of the three already-permitted simple cycle electric generating units into a 2x1 combined cycle configuration at the Brandy Branch facility (hereinafter referred to as the "Generating Station") near Baldwin City, Duval County, Florida. The Generating Station is currently permitted to construct and operate three simple cycle combustion turbine (SCCT) units.

The Generating Station will include the conversion of two of the three SCCT units (Units 2 and 3), to combined cycle combustion turbine (CCCT) units rated at approximately 170 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a backup fuel. Units 2 and 3 are located adjacent to Unit 1. The only new major support facilities for Units 2 and 3 will be the heat recovery steam generators (HRSGs), a steam turbine, and a cooling tower. All other needed facilities such as fuel oil storage tanks exist or are currently under construction as part of the simple cycle project.

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

2.0 Project Characterization

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

2.1 Project Location

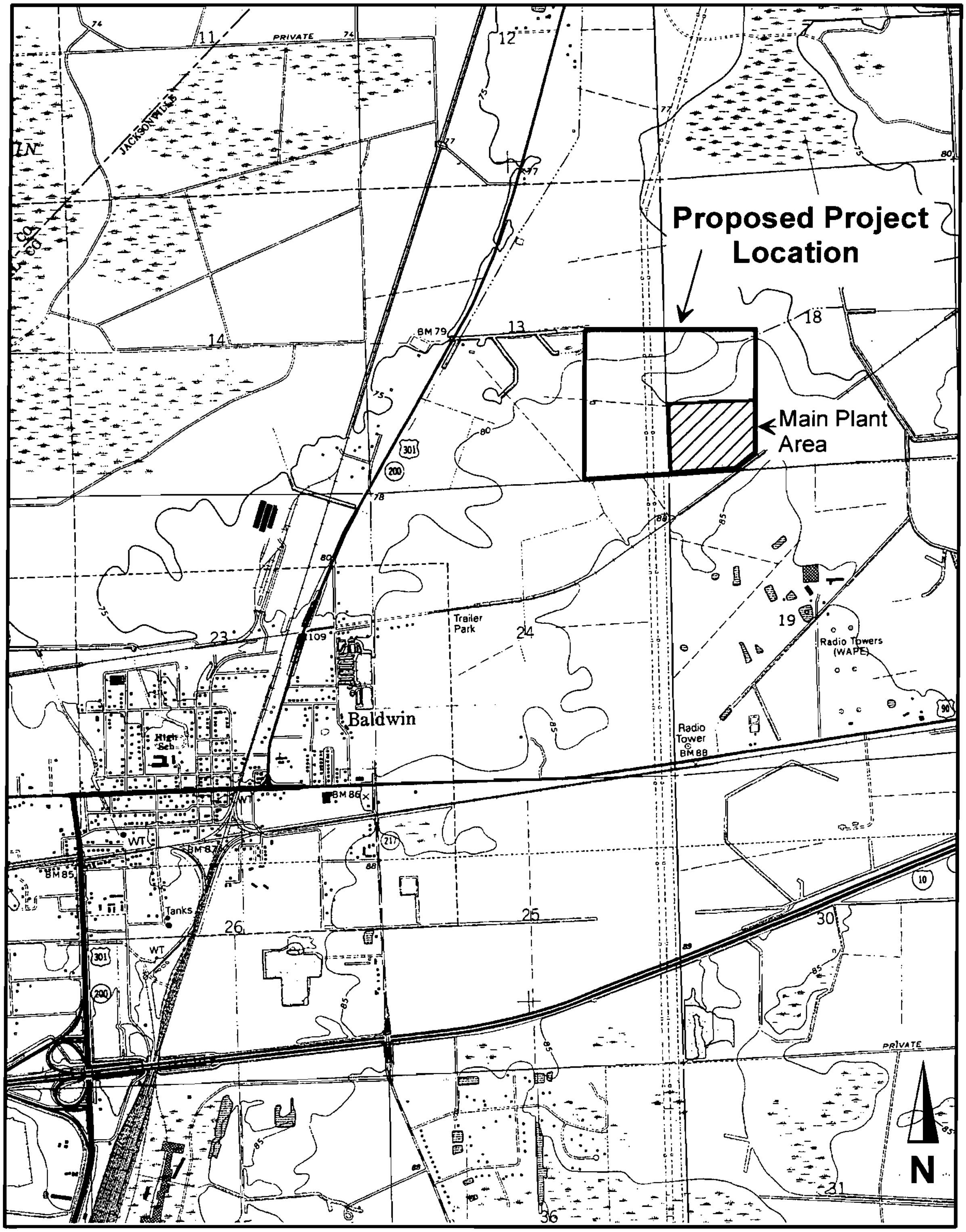
The Generating Station is located in the western, rural part of Duval County, Florida. Figure 2-1 shows the general location of the Generating Station which is approximately 1 mile northeast of Baldwin City. The approximate UTM coordinates of the Generating station are 408,774.1 m East and 3,354,530.8 m North. The nearest Federal PSD Class I Areas are the Okefenokee Wilderness Area and the Wolf Island Wilderness Area located approximately 34 kilometers (km) northwest and 127 km northeast of the Generating Station, respectively.

The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

The Generating Station will be located at the Brandy Branch facility which currently is permitted to construct three SCCT units and related support facilities. Two of the three SCCT units are proposed to be converted to CCCT units. The two CCCT units will be operated in a 2x1 configuration. Major equipment associated with the each CCCT unit will consist of a General Electric (Model PG7241FA) combustion turbine generator (CTG), heat recovery steam generator (HRSG) with supplemental firing, steam generator, and a cooling tower. Fuel oil storage tanks for each of the CCCT have already been permitted as part of the Brandy Branch SCCT Facility.

The CTG/HRSG will use evaporative coolers as necessary to cool the compressor inlet air prior to its combining with fuel in the combustor of the CCCT. The thermal energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as these gases expand through the turbine sections of the CCCTs. The rotating mechanical energy will be converted into electrical energy via a shaft on the CCCT connected to an electrical generator. The remaining usable thermal energy in the combustion gases will be exchanged with water/steam in the HRSG.



Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Figure 2-1

JEASITE.SRF

Supplemental (duct) firing with natural gas will be used to increase the thermal energy of the combustion gases exhausting from each CCCT. The resulting high pressure steam produced in each HRSG will be expanded through a single steam turbine. The rotating mechanical energy generated by the steam turbine will be converted into electrical energy via a shaft connected to an electrical generator. The exhaust gases will exit to the atmosphere after leaving the HRSG stack.

A site arrangement showing the various emission units and structures/buildings at the Generating Station is presented in Figure 2-2.

2.3 Project Emissions

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

- Two General Electric CCCT/HRSGs with supplemental firing.
- One ten (10) cell cooling tower.

2.3.1 Project Emissions

Performance data for the CTG/HRSG, based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel oil firing, and ambient air temperatures of 20° F, 59° F, and 95° F are provided in Attachment 1.

Ambient temperature data was selected based on meteorological data from Jacksonville, FL. An ambient temperature of 20° F represents the lowest anticipated site temperature and maximum power generation. An ambient temperature of 59° F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 95° F represents the highest anticipated site temperature which corresponds to the lowest heat input rate for the combustion turbine and results in the maximum required duct firing and evaporative cooling rates to maintain the desired plant electrical output.

The maximum pound per hour emission rates at the annual average site temperature for combined cycle operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.4 Maximum Potential to Emit

The potential to emit was estimated from the maximum hourly emission rate for each pollutant at an ambient temperature of 59° F (average annual) in combined cycle operation, 50 to 100 percent load, and 288 hours of distillate fuel oil firing (0.05 percent sulfur) with the remainder of the year on natural gas. The potential to emit for each pollutant is summarized in Table 2-2. The potential to emit estimate for PM/PM_{10} includes the particulate emissions resulting from the operation of the cooling tower. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 2.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs: the PSD program outlined in 40 CFR 52.21; and, the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the Generating Station, as administered by the State of Florida under 62-212.400, FAC, Stationary Sources - Preconstruction Review, Prevention of Significant Deterioration.

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

Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NO_x	23.62	112.41
SO_2	1.16	102.97
CO	52.58	67.86
PM/PM_{10}**	19.80	62.10
VOC	3.49	7.68
H_2SO_4	0.18	12.61

*Maximum pound per hour emission rates at 59° F, combined cycle operation, burning natural gas and distillate fuel oil.
** Includes the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

Table 2-2 PSD Applicability			
Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	232.48[a]	40	yes
SO_2	39.48[a,b]	40	no
CO	465.00[a]	100	yes
PM/PM_{10}	185.63[a,c]	25/15	yes
VOC	31.78[a]	40	no
Sulfuric Acid Mist	5.16[a]	7	no
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.0000495[d]	0.1	no
Beryllium	0.00000228[d]	0.0004	no
Lead	0.01[d]	0.6	no
Total HAPs	6.61[e]	10/25	no

[a]Based on maximum lb/h emission rate at 59° F conditions for all loads and operating scenarios; assuming 8,472 and 288 hours per year of natural gas and distillate fuel oil firing, per turbine, respectively.

[b]Based on 0.05% sulfur distillate fuel oil and 0.2 gr/100 scf sulfur natural gas.

[c]Includes the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

[d]Based on AP-42 emission factors, a maximum heat input of 2,059.4 MMBtu/hr and distillate fuel oil firing for 288 hours per year.

[e]HAP calculation sheet in Attachment 2.

Note: PTE calculations are provided in a spreadsheet included in Attachment 2.

2.5.1 Prevention of Significant Deterioration

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

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Brandy Branch Simple Cycle facility is a major source, having a PTE greater than 250 tpy for at least one regulated pollutant. Additionally, the estimated emission increases of NO_x, CO, and PM/PM_{10} resulting from the proposed modification (i.e., conversion of Units 2 and 3 from simple cycle turbine units to combined cycle turbine units), exceed the PSD significant emissions levels of 40, 100, 25/15 tpy, respectively. Therefore, the Generating Station emissions of NO_x, CO, and PM/PM_{10} are subject to PSD review as a modification to an existing major source. The PSD review includes a BACT analysis, air quality impact analysis, and an assessment of the Generating Station's impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

The 1977 Clean Air Act (CAA) established revised conditions for the approval of pre-construction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the act emitted in significant amounts from new major sources or modifications. The new major sources proposed for this Generating Station include two combined cycle combustion turbines and a cooling tower that are subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this Generating Station.

The following is a summary of the BACT determination and associated emission rates for two GE 7241(FA) combustion turbines operating with duct burners in combined cycle mode to be installed for JEA. Emissions are based on the GE 7241(FA) combined cycle combustion turbine units with duct burner firing. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each combustion turbine-generator/heat recovery steam generator (CTG/HRSG) unit operating at full load with duct firing for 8,472 hours per year on natural gas at an ambient temperature of 59 °F. Also included in this BACT are emissions for each combustion turbine-generator (CTG) unit firing fuel oil at full load operation without duct firing for 288 hours per year at an ambient temperature of 59 °F.

GE 7241(FA) CTG/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with an SCR during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.

- Burning natural gas at full load, an emission limit of 0.0131 lb/MMBtu (23.6 lb/hr, 3.5 ppmvd at 15 percent O_2).
- Burning fuel oil at full load, an emission limit of 0.0580 lb/MMBtu (112.4 lb/hr, 15 ppmvd at 15 percent O_2).

Carbon monoxide (CO) emissions – BACT was determined to be good combustion controls to achieve a CO emission limit of 0.0291 lb/MMBtu (52.6 lb/hr, 12.21 ppmvd at 15 percent O_2) during natural gas firing and 0.0350 lb/MMBtu (67.9 lb/hr, 14.17 ppmvd at 15 percent O_2) during fuel oil firing.

Particulate emissions (PM/PM_{10}) -- BACT was determined to be good combustion controls and combustion air filters to achieve a PM/PM_{10} emission limit of 0.0110 lb/MMBtu (19.8 lb/hr) during natural gas firing. BACT was determined to be good combustion controls and combustion air filters to achieve a PM/PM_{10} emission limit of 0.0320 lb/MMBtu (62.1 lb/hr). The PM/PM_{10} emission estimates conservatively include front and back half catch as well as the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent resulting in emissions of 0.08 lb/hr.

3.1 Project Description

The electric generating facility (hereinafter referred to as the "Generating Station") to be installed for JEA at the Brandy Branch site will consist of two (2) General Electric (GE) 7241(FA) combined cycle combustion turbines (CCCT) and respective cooling towers. The combined cycle operation consists of using two combustion turbines and two-heat recovery steam generators (HRSGs) with a steam turbine in a Rankine power cycle. The configuration is used to generate additional power, although the CTG/HRSG power plant is well suited for continuous operation at full load, it is not well suited for large load changes or quick and frequent startups and shutdowns. Each CTG/HRSG configuration will also include a supplemental duct burner (DB) located in the outlet duct from the combustion turbine to provide additional heat for high power demand periods. The HRSG will be used to recover energy from the high temperature flue gas generated by each combustion turbine and duct burner. A steam turbine will be used to generate additional electricity from the steam produced in the HRSG. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas.

The output ratings of each GE PG7241(FA) combine cycle combustion turbine will be nominally 170 MW. The proposed operating scenario for the combustion turbines consists of operating up to 8,472 hours per year while firing natural gas and operating up to 288 hours per year while firing fuel oil.

3.2 Basis of Combustion Turbine BACT Analysis

This section describes the basis of the combustion turbine BACT analysis. Information is provided on such issues as the BACT methodology and approach used. The parameters and factors used in developing the analysis are identified.

3.2.1 Regulatory and Methodology Basis

The BACT analysis for the GE 7241(FA) combustion turbine units with and without duct burner firing is based on certain regulatory requirements and Generating Station assumptions. The following is a summary of the requirements and assumptions for which this BACT analysis is based.

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal New Source Performance Standards (NSPS) for combustion turbines with heat input greater than 10 MMBtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for NO_x emissions. No NSPS criteria have been established for limiting CO, VOC and PM/PM_{10} emissions. The following flue gas emission limit is established by NSPS for Subpart GG units:
- NO_x: 75 ppmvd at 15 percent O_2, corrected for fuel nitrogen content and turbine heat rate.
- Federal NSPS for electric utility steam generating units for which construction is commenced after June 9, 1989 with a maximum design heat input (fuel burn rate) of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr (40 CFR 60 Subpart Dc) establish limiting criteria for SO_2 and particulate emissions only. No NSPS criteria have been established for limiting NO_x, CO and VOC emissions. Each duct burner for this Generating Station is approximately 85 MMBtu/hr.

As defined in the air permit application, operation of the Generating Station will result in an increase in the potential to emit emissions of NO_x, CO, and PM/PM_{10} in excess of the major source PSD threshold levels set for these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy and environmental considerations. 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 United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under Lowest Achievable Emission Rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, 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.

3.2.2 Operations/Emissions Basis

As mentioned previously, the proposed operating scenario for the CTG/HRSGs with duct firing is 8,472 hours per year while firing natural gas. Moreover, the proposed operating scenario for firing fuel oil for each CTG is 288 hours per year. Table 3-1 shows the uncontrolled emission rates for a GE 7241(FA) combined cycle combustion turbine unit with duct burner firing natural gas and without duct burner firing fuel oil at 100 percent of base load at an average annual site temperature of 59 °F. The emissions shown in Table 3-1 are controlled with dry low NO_x burners during natural gas firing and water injection during fuel oil firing and lb/MMBtu values are based on the higher heating value (HHV).

Table 3-1
Uncontrolled Emission Rates Per GE 7241(FA) CCCT Unit

Emission Parameter	GE 7241(FA) with Duct Firing (Natural Gas)[a]	GE 7241(FA) without Duct Firing (Fuel Oil)[b]
NO_x, ppmvd at 15% O_2	9.2	42.0
NO_x, lb/hr	61.8	331.5
NO_x, lb/MMBtu (HHV)	0.0342	0.1709
CO, ppmvd at 15% O_2	12.2	14.2
CO, lb/hr	52.6	67.9
CO, lb/MMBtu (HHV)	0.0291	0.0350
PM, lb/hr	19.8	62.1
PM, lb/MMBtu (HHV)	0.0110	0.0320
PM_{10}, lb/hr	19.7	60.4
PM_{10}, lb/MMBtu (HHV)	0.0110	0.0311

Notes:

[a] Total emissions are based on 8,472 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 59 °F.

[b] Total emissions are based on 288 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 59 °F.

3.2.3 Economic Basis

Economic analysis used to determine the capital and annualized costs of the control technologies were based on EPA methodologies shown in the EPA 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 project developer cost factors and vendor budgetary cost quotes. Table 3-2 lists the economic criteria used in the analysis of BACT alternatives.

Table 3-2
Generating Station Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	9.64
Economic Life years	20
Capital Recovery Factor, (20 years)	0.1146
Capital Recovery Factor, (3 years)	0.3996
Labor Cost, $/man-hr	38.0
Natural Gas Cost, $/MMBtu	2.74
Anhydrous Ammonia Cost, $/ton	250
Energy Cost, $/kWhr	0.022
Catalyst Life Guarantee, years	3
Sales Tax, percent	3

3.3 Combustion Turbine NO_x and CO BACT Analysis

The objective of this analysis is to determine BACT for NO_x and CO emissions from the combined cycle combustion turbines. This includes the CTs and supplemental firing in the HRSG as a total unit during natural gas firing. The CTs without supplemental firing in the HRSG will only be considered when fuel oil firing. Unless otherwise noted the NO_x and CO emission rates described in this section are corrected to 15 percent oxygen.

3.3.1 NO_x BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Attachment 3. A review of the BACT/LAER Clearinghouse documents (CAPCOA, 1985 - 2000; USEPA, 1990 - 2000) indicates that the lowest emissions achieved for a natural gas fired combustion turbine is 2.0 ppmvd for the Federal Cold Storage Cogeneration facility located in California. The 2.0 ppmvd was achieved for six months (June 1997 to December 1997) with 15 minute CEM averaging periods. Further, Region IX of the EPA has deemed the limit of 2.0 ppmvd at 15 percent oxygen was achieved in practice with three hour averaging. The emissions from that unit are controlled through the use of water injection and a SCONO$_x$ system. It should be noted that the Federal Cold Storage Cogeneration facility is located in a non-attainment area for ozone, with NO_x regulated as a non-attainment pollutant. Thus, this emission level represents LAER for CTG/HRSG. It should also be noted that this is a small, 222 MMBtu/hr GE model LM2500-M-2 combine cycle gas turbine that is producing 32 MW (cogeneration). The current use of this specific control application on CTG/HRSG Generating Station applications (e.g., units under 30 MW) is not considered applicable to the Generating Station as will be discussed.

In addition, the Sacramento Power Authority (Campbell Soup) located in the Sacramento Metropolitan AQMD in California has set a 3.0 ppmvd NO_x emission limit for a natural gas fired CTG/HRSG. The emissions from that unit are controlled through the use of standard combustors, water injection, and selective catalytic reduction (SCR). This unit consists of a 1,257 MMBtu/hr combined cycle natural gas fired Siemens V84.2 gas turbine generator with water injection for power augmentation and 200 MMBtu/hr of supplemental firing capacity producing 103 MW. This combustion turbine emission limit is noted in the Clearinghouse as being representative of LAER at the time of the permit (1994). Another stringent NO_x emissions limit for a gas fired CT is 3.5 ppmvd for the Brooklyn Navy Yard Cogeneration Project located in New York. The emissions from that unit are controlled through the use of dry low NO_x burners and SCR. Furthermore, a recent project listed in the CAPCOA BACT/LAER Clearinghouse database is the Sutter Power Plant in the Feather River AQMD in California has been permitted at 2.5 ppmvd at 15 percent O_2 for a one hour average. The facility will consist of two-combined cycle 1,900 MMBtu/hr gas fired, 170 MW Siemens Westinghouse 501FD turbines with 170 MMBtu/hr HRSGs driving a common 160 MW steam turbine. The NO_x emissions are to be controlled by dry low NO_x combustors, selective catalytic reduction, and low NO_x duct burners. It should also be noted that this facility has an ammonia slip permitted at 10 ppmvd at 15 percent O_2 to achieve such low NO_x emissions. The facility is listed in the CAPCOA BACT/LAER Clearinghouse documents, but is still under construction and demonstration of this level of NO_x control has not been achieved in practice at this time.

3.3.2 CO BACT/LAER Clearinghouse Reviews

A list of the top pertinent BACT/LAER decisions is attached in Attachment 3. A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. The 617 MMBtu/hr combustion turbine units fire natural gas. The low emissions are achieved by reducing CO emissions by 80 percent (from 9 ppmvd to 1.8) through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in non-attainment areas for CO and ozone (VOC control required).

3.3.3 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. 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:

1) Water/Steam Injection
2) Dry Low-NO_x (DLN) Burners
3) Xonon

Post Combustion Type:

1) Selective Non-Catalytic Reduction (SNCR)
2) Selective Catalytic Reduction (SCR)
3) $SCONO_x$

3.3.3.1 Water or Steam Injection. NO_x emissions from the combustion turbines 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. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. However, there is a point at which the amount of water injected into the combustion turbine seriously degrades its reliability and operational life. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions that are formed as a result of incomplete combustion.

The development of DLN burners has replaced the use of wet controls except for certain cases such as oil firing. Therefore, the use of water injection will be considered for operations during oil firing and will be eliminated from further evaluation for control during natural gas firing for reducing NO_x emissions in this BACT analysis.

3.3.3.2 Dry Low NO_x Burners. NO_x 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 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 fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion systems as the state of the art for NO_x controls in combustion turbines.

DLN combustion turbine burner designs are available which use improved air/fuel mixing and reduced flame temperatures to limit thermal NO_x formation. DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required, which results in low NO_x emissions.

The controlled emission level will vary from manufacturer to manufacturer of the combustion turbine. The F-Class combustion turbines proposed for the Generating Station are manufactured by GE and have DLN burners that can achieve a NO_x emission level of approximately 9 ppmvd at 15 percent O_2. It should also be noted that as with the standard combustor with water injection, the DLN burners could be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

Due to the proven performance of the DLN burner technology, this method of NO_x emissions control will be considered in this BACT analysis.

3.3.3.3 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 carbon monoxide 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 technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers. To date, commercialization of this technology on utility size combustion turbines such as proposed for the Generating Station has not been developed.

Due to the technical and commercial limitations of this technology, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

3.3.3.4 Selective Non-Catalytic Reduction. Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,500 to

1,900 °F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (slip). Operation above the temperature window results in increased NO_x emissions. The exhaust temperature at the exit of a combustion turbine, which is approximately 1,100 °F for these units, is too low for any consideration of this technology.

Due to the technical and operational limitations on temperature and available reaction time, this method of post-combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

3.3.3.5 Selective Catalytic Reduction. Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CTG/HRSG projects for the past five 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 10 ppm, 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 vast majority of SCR system installations (greater than 95 percent). The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600 to 750 °F. At temperatures above 800 °F permanent damage to the vanadium/titanium catalyst occurs. For the combined cycle turbines proposed for the Generating Station, this temperature window does exist. The flue gas temperature is reduced in the HRSG of the CTG/HRSG proposed for this Generating Station and would typically range from 200 to 700 °F. Accordingly, a vanadium/titanium catalyst can be installed at this Generating Station. Therefore, the vanadium/titanium-based catalyst will be evaluated further for these units.

The operation of an SCR could present a negative impact on the environmental performance of the combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO_3) in the flue gas to form ammonia-sulfur salts, such as ammonium bisulfate. These compounds form when the flue gas cools upon leaving the stack. This particulate adds to the emissions of PM_{10} from the unit.

Limitations to accurate measurements of emissions consistently below the 3 to 3.5 ppmvd are also a concern. Limitations in measuring any lower level of emission include sampling methods, analyzer limitations, and calibration gas error. Current EPA procedures and standards recognize such limitations. Currently, 40 CFR Part 75 allows emission monitors with span ranges of less than 200 ppmvd to have calibrations that deviate by up to 10 ppmvd and still be considered "in control." The difference of 1 ppmvd in the low values being measured will be in the "noise" range of the emission monitoring system. Lowering the limit to a level below 3.5 ppmvd will only magnify this lack of accuracy, thereby increasing the potential for emission exceedances without providing any further real reduction in emissions. A report by the American Society of Mechanical Engineers (ASME) on reviewing current measuring and monitoring practices indicated that relative accuracy results varied from 1.3 to 34 percent when testing low NO_x emitters.

Because the SCR system requires the regulation of ammonia injection based on the 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 values is below the permitted values. 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 3.5 ppmvd also raises concerns with the additional ammonia that maybe 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 that increase ammonia emissions will be counter productive to the reduction of overall emissions since ammonia presents an emission problem itself and is a precursor to $PM_{2.5}$.

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

3.3.3.6 SCONO$_x$. A third, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with ABB Alstom Power, is SCONO$_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. As previously noted, the South Coast Management District has declared LAER as 2.0 ppm of NO_x, based on this technology. Although this system has been proven on a small size unit, scale up concerns still exist with regard to the use of this technology on large units. To date, SCONO$_x$ has not been demonstrated in practice for a GE 7241(FA) (i.e., Frame 7 or F-Class) combustion turbine.

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 and thereby reducing plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300 to 700 F. ABB Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst. This recycled material can account for as much as one-third the cost of the replacement 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 six months to one 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 with a potassium carbonate reagent, 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 it 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 ten months on a small LM-2500 combined cycle CT unit before it was taken out of service because of poor regeneration gas distribution.

A letter dated November 19, 1999 from EPA Region I had concerns regarding if $SCONO_x$ could handle the increased gas flow, mechanical durability and scale-up of the damper/louver system, reliability of the regenerative gas distribution system, the performance of the sulfur removal method, and catalyst performance guarantees. The EPA had concerns with the technical uncertainties and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. In addition there are major issues with applying $SCONO_x$ to distillate fuel oil applications, given the higher sulfur content in the fuel. According to the EPA letter, ABB Alstom Power has executed a re-design and testing program to develop the $SCONO_x$ system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

The November 19, 1999 EPA letter addresses that ABB Alstom had redesigned and fabricated a full-scale louver prototype system for larger turbine applications. In addition ABB had cycled the prototype louver system 102,000 times (approximately 5 years of operation) at operating temperatures of 620 F and enclosed the system in a hot casing shell design to avoid thermal stresses from the heat recovery steam generator. ABB Alstom has increased the catalyst module and regenerative gas distribution system that supplies gas to each individual module. Although, ABB Alstom has only performed computational fluid dynamics (CFD) modeling to try and verify the gas regeneration system. ABB Alstom has addressed degradation of the $SCONO_x$ catalyst from sulfur compounds found in natural gas, causing frequent system shutdowns, by verifying that a $SCOSO_x$ catalyst can be used upstream of the $SCONO_x$ catalyst. Furthermore, they claim the two catalysts are compatible and that the combined system will maintain sulfur and NO_x removal performance levels under different gas stream conditions. ABB Alstom Power will provide performance guarantees to all owners and operators of natural gas fired combined cycle combustion turbines, regardless of size or O&M. The EPA had them confirm the accuracy and correctness of their technical information in a response dated November 29, 1999. ABB Alstom has re-designed their $SCONO_x$ system for large turbine applications, but to date this new re-designed system has not been demonstrated in practice.

Another concern is the removal and replacement of the catalyst for re-coating without adversely impacting unit availability. The larger volume of catalyst used in an F class combustion turbine will require a significant period of washing or will necessitate the purchase of several spare catalyst modules.

The $SCONO_x$ system would also impact the power generation of the proposed facility. The flue gas pressure drop due to the catalyst is larger for the $SCONO_x$ process (approximately 4 to 5 in. w.g.) than the SCR process (approximately 2 to 3 in. w.g.). This increase in backpressure would result in an increase in lost power generation.

$SCONO_x$ is a technology that has effectively reduced emissions at the Federal Cold Storage facility thus far, and may have future promise. While mechanically very complicated, $SCONO_x$ technology allows for transient operation (load changes) and no ammonia issues are present, such as transportation, storage, or slip emissions. In addition, the wide operating temperature range has the potential for flexibility for future projects. The $SCONO_x$ catalyst can be placed in the most cost-effective location in an HRSG. The $SCONO_x$ catalyst can also significantly reduce CO emissions, thus reducing the need for an oxidation catalyst. However, there are a number of serious concerns regarding $SCONO_x$ that still need to be addressed prior to application to a Frame 7 or Class F machine. They include:

- Scale-up design issues for increasing the size of the application by 6 times from a LM-2500 to a Frame F combustion turbine. Scale-up design issues include damper size and proper distribution of regeneration gas.
- Mechanical system reliability: Damper and damper bearings are moving parts in the flue gas system that may present maintenance problems.
- On-line removal of catalyst for washing, including mechanics of how it is to be accomplished, time period, labor (cost), and safety issues.
- $SCOSO_x$ reliability: The SO_2 guard catalyst bed ($SCOSO_x$) can cause contaminated regeneration gas (containing sulfur and sulfur acids) to be handled, thereby questioning the effectiveness and reliability of the catalyst.
- Increased pressure drop.
- Proprietary Issue: $SCONO_x$ catalyst is a proprietary catalyst leading to concerns regarding long-term pricing.
- Warranty Issues: Since Goal Line is a relatively small company, there has been concern in the past regarding their ability to follow through with respect to potential warranty claims, not only for any single installation, but also in the event that multiple claims were to be made. ABB Alstom has signed a licensing agreement which will provide the financial backing and credibility required for warranties and guarantees. ABB Alstom has guaranteed the performance of their system, but operational risks associated with the use of $SCONO_x$ still need to be resolved.
- Financial Concerns: Lenders will have to assume performance and operational risks associated with the use of $SCONO_x$. The full-scope price without installation for a

$SCONO_x$ system is estimated to be 4 times larger than installing an SCR system on a large scale combined cycle facility.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology is currently limited to combined cycle CT units under 32 MW. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Generating Station, this system will be evaluated in this BACT analysis.

3.3.4 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increase the emissions of CO. CO 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. 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.

A current CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary and oxidizing catalysts, dependent on the uncontrolled emission level, are capable of reducing CO emissions from 80 to 90 percent.

Another CO control technology that was screened was the previously discussed $SCONO_x$ process. The $SCONO_x$ system reduces CO emissions by oxidizing the CO to CO_2. As noted for the NO_x control evaluation, the $SCONO_x$ technology may have future promise. The application for this technology is currently limited to combined cycle CT units under 32 MW. The large size of the units proposed for this Generating Station (170 MW) as compared to the size of the $SCONO_x$ operating plant makes the potential scale-up challenging and unpractical. Although, there are technical concerns with using this new technology related to the operating plant size proposed for the Generating Station, this system will be evaluated in this BACT analysis.

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

3.3.5 Combined NO_x and CO Control Technology Summary

In-combustor NO_x and CO control by advanced combustion controls using dry low NOx burners is the least stringent control technology considered for this Generating Station. However, the use of an SCR system and oxidation catalyst or the $SCONO_x$ system to reduce emissions after combustion are technologies capable of achieving significantly lower emissions. 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 NO_x and CO 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 and fuel oil firing for all operating loads for the CTG/HRSGs.
- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 3.5 ppmvd at 15 percent O_2 and CO to 1.2 ppmvd at 15 percent O_2 emissions from each combustion turbine with duct burner firing natural gas. The addition of an SCR system and oxidation catalyst to reduce outlet NO_x to 15 ppmvd at 15 percent O_2 and CO to 1.4 ppmvd at 15 percent O_2 emissions from each combustion turbine while firing fuel oil.
- The addition of a $SCONO_x$ system to reduce outlet NO_x emissions from each combustion turbine with duct burner firing natural gas and each combustion turbine firing fuel oil to 2.0 ppmvd at 15 percent O_2.

The SCR system with a 3.5-ppmvd NO_x emission limit and an oxidation catalyst will be compared to the $SCONO_x$ system with a 2.0 ppmvd NO_x emission limit.

The NO_x and CO emissions per CTG/HRSG unit with application of the above possible controls are summarized in Tables 3-3 and 3-4 for natural gas and fuel oil firing, respectively.

Table 3-3
Estimated NO_x and CO Emissions
From Alternate Combined Control Technologies Per GE 7FA CCCT with Duct Firing During Natural Gas Firing.

	Control Technology Alternatives		
	Dry Low NO_x Combustors	SCR/Oxidation Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	9.2	3.5	2.0
lb/hr	61.8	23.6	14.4
lb/MMBtu	0.0342	0.0131	0.0079
tons per year	261.8	100.0	57.2
Percent reduction	N/A	62%	78%
NO_x BACT Analysis (Annual)[a] tons per year	261.8	100.0	57.2
CO Emissions			
ppmvd (at 15 percent O_2)	12.2	1.2	1.2
lb/hr	52.6	5.3	5.3
lb/MMBtu	0.0291	0.0029	0.0029
tons per year	222.7	22.5	22.5
percent reduction	N/A	90%	90%
CO BACT Analysis (Annual)[a] tons per year	222.7	22.5	22.5

Notes:

[a] Total emissions are based on 8,472 hours per year firing natural gas at 100 percent of base load with duct firing at an ambient temperature of 59 F.

Table 3-4
Estimated NO_x and CO Emissions
From Alternate Combined Control Technologies Per GE 7FA CCCT
During Fuel Oil Firing.

	Control Technology Alternatives		
	Dry Low NO_x Combustors	SCR/Oxidation Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	42.0	15	2.0
lb/hr	331.5	112.4	15.8
lb/MMBtu	0.1709	0.0580	0.0081
tons per year	47.7	16.2	2.3
percent reduction	N/A	64%	95%
NO_x BACT Analysis (Annual)[a] tons per year	47.7	16.2	2.3
CO Emissions			
Ppmvd (at 15 percent O_2)	14.2	1.4	1.4
lb/hr	67.9	6.8	6.8
lb/MMBtu	0.0035	0.0035	0.0035
tons per year	9.8	0.98	0.98
Percent reduction	N/A	90%	90%
CO BACT Analysis (Annual)[a] tons per year	9.8	0.98	0.98

Notes:

[a] Total emissions are based on 288 hours per year firing fuel oil at 100 percent of base load without duct firing at an ambient temperature of 59 °F.

3.3.6 Evaluation of Feasible Technologies

The following evaluation considers energy, environmental and economic impacts for the potential NO_x and CO BACT scenarios evaluated.

3.3.6.1 $SCONO_x$ Energy Impacts. The use of a $SCONO_x$ system will increase the energy requirements on the system. The $SCONO_x$ system will increase the backpressure on each combustion turbine by about 4 inches water gauge (in. w.g.). This will reduce the output of each CTG/HRSG 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. It is estimated the unit will be offline for a period of 4 days per year to accommodate the washing process. Furthermore, there will be an energy lost due to steam consumption from the regeneration system. The steam serving as a carrier gas for the natural gas will be required regardless of the $SCONO_x$ location in the HRSG. ABB Alstom estimated that between 15,000 to 20,000 lb/hr of steam will be used in the regeneration production. These three effects will be added together to determine the total lost power generation and are included in the annualized cost estimate. The $SCONO_x$ system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. ABB Alstom estimated that approximately 10 to 20 kW would be consumed during operation of the $SCONO_x$ 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. ABB Alstom estimated that 2 percent of the carrier gas will consist of the regeneration gas. Therefore, approximately 7,000 ft^3/hr (300 lb/hr) will be consumed in the regeneration process of the $SCONO_x/SCOSO_x$ catalyst. The annualized cost of natural gas consumption is included in the annualized cost analysis.

3.3.6.2 $SCONO_x$ 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. 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 a $SCONO_x$ system would directly counter this initiative.

3.3.6.3 SCR Energy Impacts. The use of an SCR system impacts the energy requirements of the Generating Station. The SCR system requires vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. In addition, an SCR system catalyst will increase the backpressure on each combustion turbine. The SCR system will add about 1.6-inch water gauge (in. w.g.) backpressure to the units, respectively. This will reduce the output of the each unit by approximately 0.1 percent. Increased power consumption and lost power generation are included in the annualized cost estimate.

3.3.6.4 SCR Environmental Impacts. The vanadium content of the SCR catalyst may contribute 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. According to 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 HRSG stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd (uncorrected), unless that limit is shown to be inappropriate. Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. A design value of 10 ppmvd (uncorrected) is appropriate for a clean fuel facility such as this Generating Station. With fresh catalyst ammonia slip emissions will be very low. However, as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and may be classified as hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

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.

3.3.6.5 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 the combustion turbine output by approximately 0.1 percent. The cost of lost power revenue due to the backpressure is included in the economic analysis.

3.3.6.6 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 30 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the CO 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 (H_2SO_4) mist in the atmosphere. The increase in H_2SO_4 emissions would increase PM_{10} (matter less than 10 microns in diameter) 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 CO 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.

3.3.6.7 Economic Impacts for SCR/Oxidation Catalyst and SCONOx. The use of an SCR and oxidation catalyst has significant economic impacts to the Generating Station. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 8,472 hours per year on natural gas and operating the combustion turbine for 288 hours per year of fuel oil. The capital and annualized cost for the $SCONO_x$ system also includes the $SCOSO_x$ system.

3.3.6.7.1 Capital Costs for SCR/Oxidation Catalyst and SCONOx. Table 3-5 presents the capital costs for installing an SCR/Oxidation Catalyst and $SCONO_x$ system on each CTG/HRSG unit during natural gas and fuel oil firing. The cost of the SCR/Oxidation Catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation, sales taxes and freight. The cost of the $SCONO_x$ system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, sales taxes and freight. The balance of plant equipment cost for $SCONO_x$ was estimated to be the same percentage as an SCR/Oxidation Catalyst system. 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 listed in Table 3-5 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the equipment cost and are site specific. The 3 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.

Total capital costs for the SCR and oxidation catalyst control system is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per unit for a 3.5 ppmvd (0.0131 lb/MMBtu) NO_x and 1.2 ppmvd (0.0029 lb/MMBtu) CO outlet emission during natural gas firing and a 15 ppmvd (0.0610 lb/MMBtu) NO_x and 1.4 ppmvd (0.0035 lb/MMBtu) CO outlet emission during fuel oil firing SCR/Oxidation Catalyst system for the combustion turbines is estimated to be $3,269,000.

The total capital costs for the $SCONO_x$ control system is also calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per unit for a 2.0 ppmvd (0.0079 lb/MMBtu) NO_x and 1.2 ppmvd (0.0029 lb/MMBtu) CO outlet emission during natural gas firing and a 2.0 ppmvd (0.0081 lb/MMBtu) NO_x and 1.4 ppmvd (0.0035 lb/MMBtu) CO outlet emission during fuel oil firing $SCONO_x$ system for each combustion turbine is estimated to be $14,716,000.

Table 3-5 Combined NO_x and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit				
	$SCONO_x$ System	**SCR/ Oxidation Catalyst**	**Low NO_x Burners**	**Remarks**
Direct Capital Cost				Cost based on emissions in Tables 3-3 and 3-4
SCR and Oxidation Catalysts System	Included	1,721,000	N/A	Estimated from Engelhard Corporation
$SCONO_x$ Catalyst	7,800,000	N/A	N/A	Estimated from ABB Alstom Power
$SCONO_x$ System	5,200,000	N/A	N/A	Estimated from ABB Alstom Power
Catalyst Reactor Housing	Included	268,000	N/A	Estimated from ABB Alstom and scaled from an estimate from Engelhard Corporation
Control/Instrumentation	Included	180,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Equipment/Storage)	N/A	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	13,000,000	2,369,000	N/A	
Sales Tax	390,000	71,000	N/A	3% of Purchased Equipment Costs
Freight	650,000	118,000	N/A	5% of Purchased Equipment Costs
Total Purchased Equipment Costs	14,040,000	2,558,000	N/A	
Direct Installation Costs				
Balance of Plant	4,212,000	767,000	N/A	For SCR & $SCONO_x$: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	**10,452,000**	**2,040,000**	Base	Catalyst cost is excluded as annual O&M cost
Indirect Capital Costs				
Contingency	2,808,000	512,000	N/A	20% of Direct Capital Cost
Engineering and Supervision	520,000	256,000	N/A	10% of Direct Capital Cost
Construction & Field Expense	260,000	128,000	N/A	5% of Direct Capital Cost
Construction Fee	520,000	256,000	N/A	10% of Direct Capital Cost,
Start-up Assistance	104,000	51,000	N/A	2% of Direct Capital Cost
Performance Test	52,000	26,000	N/A	1% of Direct Capitol Cost
Total Indirect Capital Costs	4,264,000	1,229,000	Base	
Total Installed Cost	**14,716,000**	**3,269,000**	Base	

3.3.6.7.2 Operating Costs for SCR/Oxidation Catalyst and SCONOx. Table 3-6 presents the annualized operating costs and emission rates using an SCR/Oxidation catalyst and $SCONO_x$ system during natural gas and fuel oil firing. 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 10 ppmvd the catalyst must be replaced. The oxidation catalyst is installed upstream of the ammonia injection grid and SCR catalyst, therefore there are no problems associated with ammonia slip but the CO catalyst degrade such that CO emissions increase. Currently, catalyst manufacturers are willing to guarantee an SCR and oxidation catalyst life of three years of equivalent operating hours. The catalyst replacement cost was calculated by multiplying the cost of the catalyst replacement modules by 15 percent for installation cost, 8 percent that includes sales taxes and freight, and a capital recovery factor based on the real interest rate over the 3 year guaranteed life of the catalyst.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.4 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with NO_2. The heat rate penalty cost 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 annualized operating costs for the $SCONO_x$ system include catalyst replacement, energy impacts, operating personnel, maintenance, natural gas consumption, catalyst washing, and heat rate penalty due to backpressure losses and steam usage. The $SCONO_x$ catalyst will require periodic washing and replacement throughout the life of the facility. The emissions will increase as the catalyst becomes deactivated, resulting in more frequent washing cycles. Replacement of the catalyst will result in lost power generation during the outage period. ABB Alstom is willing to guarantee $SCONO_x$ catalyst life of 3 years of equivalent operating hours.

Table 3-6 Combined NO_x and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit				
	$SCONO_x$ System	**SCR/Oxidation Catalyst**	**Low NO_x Burners**	**Remarks**
Direct Annual Cost				Cost based on emissions in Tables 3-3 and 3-4
Catalyst Replacement	3,871,000	638,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	192,000	39,000	N/A	See text for background information on this item
Reagent Feed	N/A	52,000	N/A	Assumes 1.4 stoichiometric ratio
Natural Gas Consumption	170,000	N/A	N/A	Based on 7,000 ft^3/hr required
Power Consumption	3,000	4,000	N/A	Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$
Lost Power Generation				
$SCONO_x$ Washing	544,000	N/A	N/A	Down time due to $SCONO_x$ washing period
Steam Consumption	491,000	N/A	N/A	Loss based on 15,000 lb/hr of steam required
Backpressure	103,000	72,000	N/A	Includes backpressure on CT
Annual Distribution Check	N/A	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	5,374,000	813,000	N/A	
Indirect Annual Costs				
Overhead	53,000	19,000	N/A	60% of O&M Labor
Administrative Charges	294,000	65,000	N/A	2% of Total Installed Cost
Property Taxes	405,000	90,000	N/A	2.75% of Total Installed Cost
Insurance	147,000	33,000	N/A	1% of Total Installed Cost
Capital Recovery	1,686,000	177,000	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	2,585,000	384,000	N/A	
Total Annualized Cost	**7,959,000**	**1,197,000**	N/A	
Annual Emissions, tpy	82.7	139.5	542.0	Emissions taken from Tables 3-3 and 3-4
Emissions Reduction, tpy	459.3	402.6	N/A	Emissions calculated from Tables 3-3 and 3-4
Total Cost Effectiveness, $/ton	**17,300**	**3,000**	N/A	Total Annualized Cost/Emissions Reduction
Incremental Annualized Cost	**6,762,000**	N/A	N/A	See text for background information on this item
Incremental Reduction	**119,000**	N/A	N/A	See text for background information on this item.

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 aqueous ammonia reagent for injection. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the project. $SCONO_x$ consumes a relatively small amount of power to open and close the catalyst dampers and to produce the regenerating gas. Maintenance costs will consist of routine system maintenance for each system. However, there is an additional maintenance cost associated with catalyst washing for the $SCONO_x$ system. The replacement materials are assumed to be two percent of the original cost for equipment and labor is assumed to be equal to materials. The $SCONO_x$ system will include the additional O&M cost for catalyst washing.

3.3.6.7.3 Total Annualized Costs for SCR/Oxidation Catalyst and SCONOx. Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. Table 3-6 shows the total annualized cost per unit for a SCR/Oxidation Catalyst system per combustion turbine is estimated to be $1,197,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately $3,000 per ton of NO_x and CO removed.

The total annualized costs for the $SCONO_x$ control system are calculated as the sum of the operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for a $SCONO_x$ system per combustion turbine is estimated to be $7,959,000. This annualized cost for the CTG/HRSG unit results in a cost effectiveness of approximately $17,300 per ton of NO_x and CO removed.

The incremental annualized cost system is calculated as the difference in annualized cost between the $SCONO_x$ and SCR/Oxidation catalyst. In addition, the incremental NO_x and CO reduction in tons per year is calculated as the difference in combined tons per year of NO_x and CO removed (alternative controlled baseline) between the two control technologies. Furthermore, the incremental removal cost is determined by dividing the incremental annualized cost by the controlled baseline reduction. It should be noted that this incremental cost effectiveness is considered relative to the next most stringent control alternative baseline (i.e., $SCONO_x$ compared to SCR/Oxidation Catalyst rather than just DLN). These cost increments will allow a comparison between the two removal technologies. The incremental annualized cost between $SCONO_x$ and the SCR/Oxidation Catalyst system is estimated to be $6,762,000. This results in an incremental cost effectiveness of approximately $119,000. This cost is considered high and for this application it is not cost effective to use $SCONO_x$ over a SCR/Oxidation catalyst system per CTG/HRSG unit.

3.3.7 Economic Impacts for SCR

The control of NO_x emissions separate from CO emission control is possible through the application of an SCR to the CTG/HRSG units without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emissions a separate economic analysis is required. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 8,472 hours per year on natural gas and each combustion turbine at 100 percent of base load for 288 hours per year on fuel oil.

3.3.7.1 Capital Costs for SCR System. Table 3-7 presents the capital costs for installing an SCR system on the CTG/HRSG units during natural gas and fuel oil firing to achieve a NO_x outlet emission level of 3.5 and 15.0 ppmvd. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; controls and instrumentation, sales taxes and freight. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the SCR catalyst material were based on vanadium/titanium type catalysts. The direct installation costs included the balance of plant items listed in Table 3-7 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the equipment cost and are site specific. The 3 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.

Total capital costs for the SCR system to reduce NO_x is calculated as the sum of the total direct cost less the catalyst cost and indirect installed costs per OAQPS cost methods. The total capital cost per unit for an SCR catalyst system per combustion turbine is estimated to be $2,421,000.

Table 3-7
NO_x Control Capital Cost Per GE 7FA CTG/HRSG Unit

Cost Item	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-3 and 3-4
SCR Catalysts System	975,000	N/A	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	N/A	Scaled from an estimate from Engelhard Corporation
Control/Instrumentation	140,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia Injection/Dilution Equipment	Included	N/A	Estimated from Engelhard Corporation
Ammonia Storage	200,000	N/A	Estimated from previous projects
Purchased Equipment Costs	1,583,000	N/A	
Sales Tax	47,000	N/A	3% of Purchased Equipment Cost
Freight	79,000	N/A	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,709,000	N/A	
Direct Installation Costs			
Balance of Plant	513,000	N/A	For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting
Total Direct Cost Less Catalyst	1,601,000	Base	Catalyst Cost is excluded as annual O&M Cost
Indirect Capital Costs			
Contingency	342,000	N/A	20% of Direct Capital Cost
Engineering and Supervision	171,000	N/A	10% of Direct Capital Cost
Construction & Field Expense	85,000	N/A	5% of Direct Capital Cost
Construction Fee	171,000	N/A	10% of Direct Capital Cost,
Start-up Assistance	34,000	N/A	2% of Direct Capital Cost
Performance Test	17,000	N/A	1% of Direct Capitol Cost
Total Indirect Capital Costs	820,000	Base	
Total Installed Cost	**2,421,000**	Base	

3.3.7.2 Operating Costs for SCR. Table 3-8 presents the annualized operating costs and emission rates using an SCR during natural gas and fuel oil firing. Annualized operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. The description of the operating costs and effects of ammonia consumption, backpressure, and catalyst life have already been described in Section 3.4.6.

3.3.7.3 Total Annualized Costs for SCR. The total annualized costs for the SCR system are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per unit for an SCR system per combustion turbine is estimated to be $881,000. This annualized cost for each CTG/HRSG unit results in an incremental cost effectiveness of approximately $4,600 per ton of NO_x removed.

Table 3-8 NO_x Control Annualized Cost Per GE 7FA CTG/HRSG Unit			
	SCR	**Low NO_x Burners**	**Remarks**
Direct Annual Cost			Cost based on emissions in Tables 3-3 and 3-4
Catalyst Replacement	308,000	N/A	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	35,000	N/A	See text for background information on this item
Reagent Feed	52,000	N/A	Assumes 1.4 stoichiometric ratio
Power Consumption	4,000	N/A	Includes injection blower and vaporization of ammonia for SCR
Lost Power Generation	41,000		Back Pressure on CT
Annual Distribution Check	8,000	N/A	Required for SCR, estimated as 0.5% of total direct cost less catalyst cost
Total Direct Annual Cost	448,000	N/A	
Indirect Annual Costs			
Overhead	17,000	N/A	60% of O&M Labor
Administrative Charges	48,000	N/A	2% of Total Installed Cost
Property Taxes	67,000	N/A	2.75% of Total Installed Cost
Insurance	24,000	N/A	1% of Total Installed Cost
Capital Recovery	277,000	N/A	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	433,000	N/A	
Total Annualized Cost	**881,000**	N/A	
Annual Emissions, tpy	116.7	309.5	Emissions taken from Tables 3-3 and 3-4
Emissions Reduction, tpy	193.3	N/A	Emissions calculated from Tables 3-3 and 3-4
Total Cost Effectiveness, $/ton	**4,600**	N/A	Total Annualized Cost/Emissions Reduction

3.3.8 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the Generating Station. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating each combustion turbine with duct firing at 100 percent of base load for 8,472 hours per year on natural gas and operating the combustion turbine for 288 hours per year of fuel oil.

3.3.8.1 Capital Cost for Oxidation Catalyst. Table 3-9 presents the capital costs for installing an oxidation catalyst on the CTG/HRSG units during natural gas and fuel oil firing to achieve a CO outlet emission level of 1.2 and 1.4 ppmvd, respectively. The capital costs for the systems includes the oxidation catalyst reactor, 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 listed in Table 3-9 and were calculated as percentages of the total purchased equipment costs. The total direct cost less the catalyst cost was determined such that the catalyst would be excluded, thereby eliminating the possibility of "double counting" the catalyst cost as an annualized O&M cost per OAQPS cost methods. The indirect costs were percentages of the equipment cost and are site specific. The 3 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.

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 cost per unit for an oxidation catalyst system is estimated to be $1,364,000.

3.3.8.2 Operating Costs for Oxidation Catalyst. Table 3-10 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve a 90 percent reduction in CO emissions while firing natural gas for the CTG/HRSG units. CO outlet emissions would be reduced to a maximum of 1.2 and 1.4 ppmvd during natural gas and fuel oil firing respectively, for the CTG/HRSG units. Annualized operating costs for the system includes catalyst replacement, operating personnel, maintenance costs, 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.

3.3.8.3 Total Annualized Costs for Oxidation Catalyst Total annualized costs for using the oxidation catalyst are calculated as the sum of operating costs plus capital recovery factor times the total installed costs. The total annualized cost per combustion turbine unit is estimated to be $602,000. This annualized cost per CTG/HRSG unit results in a cost effectiveness of approximately $2,900 per ton of CO removed.

Table 3-9 CO Reduction System Capital Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Oxidation Catalyst	746,000	NA	Estimated from Engelhard Corporation
Catalyst Reactor Housing	268,000	NA	Scaled from an estimate from Engelhard Corporation based on catalyst size
Control/Instrumentation	40,000	NA	Estimated
Purchased Equipment Costs	1,054,000	NA	
Sales Tax	32,000	NA	3% of Purchased Equipment Cost
Freight	53,000	NA	5% of Purchased Equipment Cost
Total Purchased Equipment Costs	1,139,000	NA	
Direct Installation Costs			
Balance of Plant	342,000	NA	8% For Foundations & Supports,14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting.
Total Direct Capital Cost Less Catalyst	817,000	Base	
Indirect Capital Costs			
Contingency	228,000	NA	20% of Direct Capital Cost
Engineering and Supervision	114,000	NA	10% of Direct Capital Cost
Construction & Field Expense	57,000	NA	5% of Direct Capital Cost
Construction Fee	114,000	NA	10% of Direct Capital Cost
Start-up Assistance	23,000	NA	2% of Direct Capital Cost
Performance Test	11,000	NA	1% of Direct Capital Cost
Total Indirect Capital Costs	547,000	Base	
Total Installed Cost	**1,364,000**	Base	

Table 3-10 CO Reduction System Annualized Cost Per GE 7FA CTG/HRSG Unit			
	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Tables 3-3 and 3-4
Catalyst Replacement	330,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	4,000	NA	See text for background information on this item
Lost Power Generation	31,000	NA	Back Pressure on Combustion Turbine
Total Direct Annual Cost	365,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	2,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	27,000	NA	2% of Total Installed Cost
Property Taxes	38,000	NA	2.75% of Total Installed Cost
Insurance	14,000	NA	1% of Total Installed Cost
Capital Recovery	156,000	NA	Capital Recovery Factor times Total Installed Cost
Total Indirect Annual Costs	237,000	NA	
Total Annualized Cost	**602,000**	NA	
Annual Emissions, tpy	23.3	232.5	Emissions taken from Tables 3-3 and 3-4
Emissions Reduction, tpy	209.3	NA	Emissions calculated from Tables 3-3 and 3-4
Total Cost Effectiveness, $/ton	**2,900**	NA	Total Annualized Cost/Emissions Reduction

3.3.9 Conclusions

To summarize the information discussed in this section of the NO_x and CO BACT, there are several significant technological concerns with utilizing the $SCONO_x$ system. First, $SCONO_x$ is still in the development and demonstration stage. Even though ABB Alstom has re-designed their $SCONO_x$ system for large turbine applications, to date this new re-designed system has not been demonstrated in practice. The LAER level of 2 ppmvd NO_x emissions based on using a combination of water injection and a $SCONO_x$ catalyst is considered unproven and technically unacceptable for this Generating Station. Although, that system was proven successful for operation at 32 MW, the plant size proposed for the Generating Station raises technical concerns with using this new technology. Second, the higher capital and annualized O&M cost of the $SCONO_x$ system will negatively impact the Projects economics. The capital cost for a $SCONO_x$ system would be approximately $14,716,000 per CTG/HRSG unit. Furthermore, installation of a $SCONO_x$ system designed to reduce NO_x and CO emissions would add approximately $7,959,000 to the annualized operating cost per CTG/HRSG unit. The resultant cost effectiveness is approximately $17,300 per ton of NO_x and CO removed for each CTG/HRSG unit. These costs are considered high for reducing NO_x and CO emissions for this Generating Station compared to an equivalent SCR and oxidation catalyst system.

The annualized and capital costs for the SCONOx system are approximately 4 and 5 times the cost for an equivalent SCR and oxidation catalyst system. The capital cost for an SCR/Oxidation catalyst system would be about $3,269,000 per CTG/HRSG unit. Installation of a SCR/Oxidation catalyst system would add approximately $1,197,000 to the annualized operating cost of each CTG/HRSG unit. The resultant cost effectiveness is approximately $3,000 per ton of NO_x and CO removed per CTG/HRSG unit. Furthermore, the incremental annualized cost of the $SCONO_x$ system compared to the SCR/Oxidation catalyst system is about $6,762,000 for each CTG/HRSG unit, which is considered high in light of the existing feasible technologies that can attain the same reductions at a lower overall cost. The $SCONO_x$ system at its current capital and annualized cost can not compete economically to a SCR/Oxidation catalyst system for this combustion turbine application. Therefore, based on economics and the lack of a demonstrated emission limit on larger CTG/HRSG units, this new system was not considered BACT for the Generating Station.

SCR catalysts have proven emissions reduction capabilities and low maintenance requirements at a variety of different facilities throughout the United States, Europe and Asia. SCR systems are representative of the BACT/LAER level of NO_x emissions reduction. SCR systems have been successfully used on numerous combined cycle combustion turbine applications. The capital and annualized operating cost for an SCR system per CTG/HRSG unit is \$2,421,000 and \$881,000, respectively. The incremental cost effectiveness for the CTG/HRSG unit is estimated to be \$4,600 per additional ton of NO_x removed. The operation of an SCR at lower emission rates will likely result in increased PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation, as well as associated ammonium bisulfate/sulfate and H_2SO_4 emissions. Therefore, based on energy, environmental and economic impacts, the use of DLN combustors with an SCR to meet an emissions level of 3.5 ppmvd (0.0131 lb/MMBtu, 23.6 lb/hr) for each natural gas fired CTG/HRSG with duct burners and 15 ppmvd (0.0580 lb/MMBtu, 112.4 lb/hr) for each combustion turbine during fuel oil firing are proposed as BACT for NO_x.

Installation of an oxidation catalyst would have negative energy, environmental and economic impacts. In summary, the oxidation catalyst would increase the backpressure on the turbine; thereby increasing emissions per unit of electric generation due to decreased turbine efficiency and increased fuel consumption. The oxidation catalyst would increase particulate emissions as a result of increased SO_3 production. In addition, the oxidation catalyst results in an increase in CO_2 emissions, which may contribute to global warming. The negative economic impacts include increased production costs due to decreased efficiency, increased capital cost for the installation of the oxidation catalyst, and increased operating cost due to periodic replacement of the oxidation catalyst.

The capital cost to install an oxidation catalyst system for a CTG/HRSG unit designed to reduce CO emissions by 90 percent would be \$1,364,000 and the annualized operating cost would be increased by \$602,000 per year. The resultant cost effectiveness on a per ton of CO removed basis is approximately \$2,900. Therefore, based on economic, environmental, and energy impacts, the proposed CO BACT for the control of CO emissions from each combustion turbine is good combustion practices to achieve a CO emission limit of 12 and 14 ppmvd at 15 percent O_2 during natural gas and fuel oil firing.

3.4 Combustion Turbine PM/PM_{10} BACT Analysis

The objective of this analysis is to determine BACT for PM/PM_{10} emissions from the combined cycle combustion turbines. This includes the combustion turbines and supplemental firing in the HRSG as a total unit.

The emissions of particulate matter from the Generating Station will be controlled by ensuring as complete combustion of the fuel as possible and by minimizing SO_2 to SO_3 oxidation. The NSPS for combustion turbines do not establish a particulate emission limit. Natural gas contains only trace quantities of non-combustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations as referenced by the State of Florida, such as the FPL Fort Myers, Santa Rosa and Tallahassee projects, the use of combustion controls is considered BACT for particulate matter and is proposed for this Generating Station. BACT was determined to be good combustion controls and combustion air filters to achieve a PM/PM_{10} emission limit of 0.0110 lb/MMBtu (19.8 lb/hr) during natural gas firing. BACT was determined to be good combustion controls and combustion air filters to achieve a PM emission limit of 0.0320 lb/MMBtu (62.1 lb/hr) and a PM_{10} emissions limit of 0.0311 lb/MMBtu (60.4 lb/hr) during fuel oil firing. PM/PM_{10} emissions conservatively include front and back half catch as well as the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

3.5 Cooling Tower BACT Analysis

Uncontrolled cooling towers can be high emitters of PM/PM_{10} under certain conditions. PM/PM_{10} 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. A portion of the water droplets emitted from the tower exhausts will evaporate leaving the suspended or dissolved solids in the atmosphere and thus subject to dispersion. Typically, drift eliminators are used to minimize drift (droplet) losses. The drift eliminator control efficiency for the proposed cooling towers is 0.002 percent resulting in emissions of 0.08 lb/hr. The drift eliminators are proposed as BACT for PM/PM_{10} for the cooling towers.

3.6 Conclusions

The following is a summary of the BACT determination and associated emission rates for two GE 7241(FA) combustion turbines operating with duct burners in combined cycle mode to be installed for JEA. Emissions are currently based on the GE 7241(FA) combined cycle combustion turbine units with duct burner firing. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for each combustion turbine-generator/heat recovery steam generator (CTG/HRSG) unit are for full load operation with duct firing at 8,472 hours per year firing natural gas at an ambient temperature of 59 °F. Also included in this BACT are emissions for each combustion turbine-generator (CTG) unit firing fuel oil at full load operation without duct firing for 288 hours per year at an ambient temperature of 59 °F.

GE 7241(FA) CTG/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with an SCR during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.

- Burning natural gas at full load, an emission limit of 0.0131 lb/MMBtu (23.6 lb/hr, 3.5 ppmvd at 15 percent O_2).
- Burning fuel oil at full load, an emission limit of 0.0580 lb/MMBtu (112.4 lb/hr, 15 ppmvd at 15 percent O_2).

Carbon monoxide (CO) emissions – BACT was determined to be good combustion controls to achieve a CO emission limit of 0.0291 lb/MMBtu (52.6 lb/hr, 12.21 ppmvd at 15 percent O_2) during natural gas firing and 0.0350 lb/MMBtu (67.9 lb/hr, 14.17 ppmvd at 15 percent O_2) during fuel oil firing.

Particulate emissions -- BACT was determined to be good combustion controls and combustion air filters to achieve a PM/PM_{10} emission limit of 0.0110 lb/MMBtu (19.8 lb/hr) during natural gas firing. BACT was determined to be good combustion controls and combustion air filters to achieve a PM emission limit of 0.0320 lb/MMBtu (62.1 lb/hr) and a PM_{10} emissions limit of 0.0311 lb/MMBtu (60.4 lb/hr) during fuel oil firing. PM/PM_{10} emissions conservatively include front and back half catch as well as the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

Cooling Tower:

Particulate emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent resulting in emissions of 0.08 lb/hr.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those PSD pollutants which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, CO, and PM/PM_{10}). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of JEA in a letter from Black & Veatch dated September 20, 2000. The FDEP provided approval of the protocol via email on September 22, 2000. A copy of the protocol and FDEP approval are presented in Attachment 4.

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 00101) air dispersion model was used to predict maximum ground level concentrations associated with the Generating Station. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to access pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

4.2 Model Input and Options

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

4.2.1 Model Input Source Parameters

The ISCST3 model was used determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios (i.e., combined or simple cycle operation), fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing the Generating Station's proposed operating load range (i.e., 50, 75, and 100 percent loads) with a representative set of stack parameters and pollutant emission rates 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). This process is referred to as enveloping.

The representative stack parameters and emission rates for each load, fuel type, and operating scenario considered in the analysis are presented in Table 4-1. A spreadsheet used in determining the load based representative emissions and stack parameters from the vendor performance data is included in Attachment 2.

4.2.2 Land Use Dispersion Coefficient Determination

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

4.2.3 GEP Stack Height Determination

Existing (Unit 1) and proposed (Units 2 and 3) buildings and structures were analyzed to determine the potential to influence the dispersion of stack emissions. EPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for the Generating Station is 77.72 m (255 ft). The actual modeled height for each HRSG stack is 57.91 m (190 ft).

4.2.4 Model Defaults

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

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

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

							Pollutant Emission Rate (g/s)		
Operating Scenario/Fuel	ISCST3 Source ID*	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	NO_x	PM/PM_{10}***	CO
CCCT/HRSG Natural Gas	S#NG1	100	57.91	5.49	18.71	368.71	3.14	2.60	6.84
	S#NG7	75	57.91	5.49	15.27	363.15	2.52	2.42	5.44
	S#NG5	50	57.91	5.49	12.68	358.15	2.01	2.42	4.48
CCCT/HRSG Distillate Fuel Oil	S#FO1	100	57.91	5.49	21.28	402.59	15.04	5.67	9.13
	S#FO7	75	57.91	5.49	16.70	397.04	12.18	5.00	6.78
	S#FO5	50	57.91	5.49	14.17	394.26	9.51	4.37	9.71
CCCT/HRSG Annualized**	S#CC1	100	57.91	5.49	18.71	368.71	3.53	2.70	n/a
	S#CC7	75	57.91	5.49	15.27	363.15	2.84	2.50	n/a
	S#CC5	50	57.91	5.49	12.68	358.15	2.26	2.48	n/a

*The "S#" character in the ISCST3 Source ID name refers to either S2,or S3, which refer to stack 2 or stack 3; CC refers to combined cycle; 1,7,or 5 refer to 100, 75, or 50 percent load; and NG or FO refer to natural gas or distillate fuel oil fired.
**Annualized emission rate based on 288 hours of distillate fuel oil firing and 8472 hours of natural gas firing.
*** Estimates of PM/PM_{10} emissions for air dispersion modeling include front half catch PM/PM_{10} estimates and the effects of SO_2 oxidation and SCR formation of ammonium sulfates.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 15 km from the center of Generating Station was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1,000 m, 250 m spacing out from 1 km to 2.5 km, 500 m spacing from 2.5 km out to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing of 100 m intervals was used along the Generating Station fenceline, and a 100 m fine grid was used at the maximum impact receptors, if the maximum predicted impacts are beyond 1,000 m and the impacts were greater than the PSD SILs. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

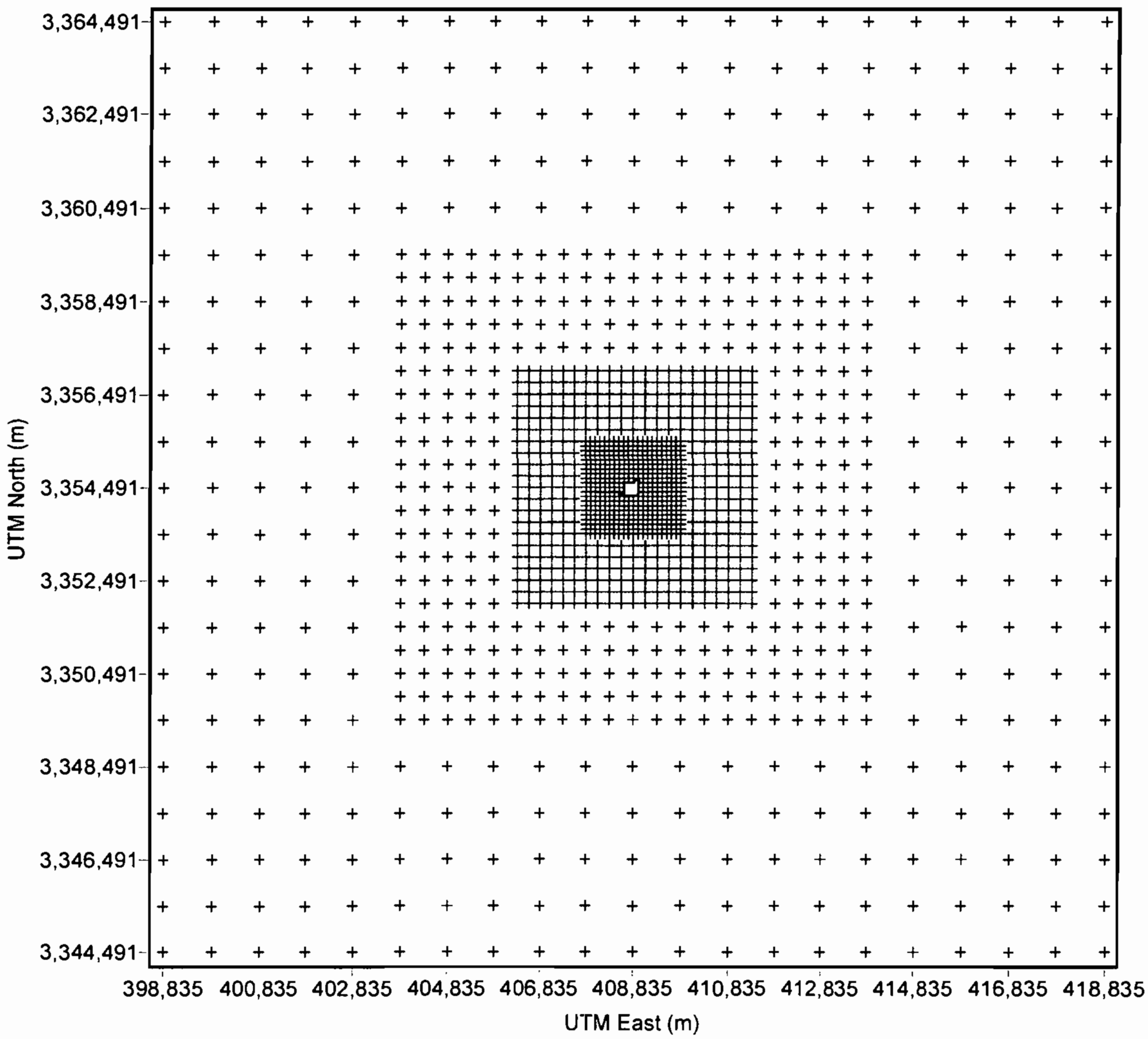
4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, FL and Waycross, GA, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Generating Station PTE exceeds the PSD significant emission thresholds for NO_x, CO, and PM/PM_{10}. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, CO, and PM/PM_{10} for each applicable averaging period. The modeled source groups for NO_x (annual), CO (1-hour and 8-hour), and PM/PM_{10} (annual) included enveloped emissions for all loads. However, the 50 percent fuel oil fired cases for PM/PM_{10} (24-hour) were modeled individually at the various temperatures presented in Section 2.3.1.

Tables 4-2 through 4-6 present the results for the 5 year modeling analysis (1984-1988) for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case.



Receptor Locations

Figure 4-1

RECEPTORS.SRF

Table 4-2
ISCST3 Model Predicted Maximum Annual Concentrations of NO_x

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1984	0.05	406,585.0	3,356,491.5
CC7		75		0.07	409,019.4	3,354,676.7
CC5		50		0.08	409,019.4	3,354,676.7
CC1		100	1985	0.05	409,019.4	3,354,460.5
CC7		75		0.08	409,019.4	3,354,460.5
CC5		50		0.10	409,019.4	3,354,460.5
CC1		100	1986	0.06	409,019.4	3,354,676.7
CC7		75		0.08	409,019.4	3,354,676.7
CC5		50		0.11	409,019.4	3,354,676.7
CC1		100	1987	0.10	409,019.4	3,354,360.5
CC7		75		0.13	409,019.4	3,354,360.5
CC5		50		**0.15**	409,019.4	3,354,360.5
CC1		100	1988	0.07	409,019.4	3,354,360.5
CC7		75		0.10	409,019.4	3,354,360.5
CC5		50		0.12	409,019.4	3,354,360.5

Table 4-3
ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location East (m)	UTM Location North (m)
Natural Gas Firing						
CCNG1	1-Hour	100	1984	43.74	409,019.4	3,354,560.5
CCNG7		75		42.99	409,019.4	3,354,560.5
CCNG5		50		41.71	409,019.4	3,354,560.5
CCNG1		100	1985	22.59	409,035.0	3,354,291.5
CCNG7		75		20.94	409,035.0	3,354,291.5
CCNG5		50		21.28	409,035.0	3,354,491.5
CCNG1		100	1986	27.04	409,035.0	3,354,591.5
CCNG7		75		28.97	409,035.0	3,354,591.5
CCNG5		50		30.03	409,035.0	3,354,591.5
CCNG1		100	1987	27.65	409,035.0	3,354,391.5
CCNG7		75		26.80	409,035.0	3,354,391.5
CCNG5		50		25.74	409,035.0	3,354,391.5
CCNG1		100	1988	27.15	409,035.0	3,354,491.5
CCNG7		75		27.11	409,035.0	3,354,491.5
CCNG5		50		26.62	409,035.0	3,354,491.5
Fuel Oil Firing						
CCFO1	1-Hour	100	1984	44.16	409,019.4	3,354,560.5
CCFO7		75		43.37	409,019.4	3,354,560.5
CCFO5		50		72.55	409,019.4	3,354,560.5
CCFO1		100	1985	24.86	409,035.0	3,354,291.5
CCFO7		75		22.59	409,035.0	3,354,291.5
CCFO5		50		36.23	409,035.0	3,354,291.5
CCFO1		100	1986	24.58	409,035.0	3,354,591.5
CCFO7		75		27.07	409,035.0	3,354,591.5
CCFO5		50		48.26	409,035.0	3,354,591.5
CCFO1		100	1987	29.00	409,035.0	3,354,391.5
CCFO7		75		27.98	409,035.0	3,354,391.5
CCFO5		50		46.39	409,035.0	3,354,391.5
CCFO1		100	1988	27.05	409,035.0	3,354,491.5
CCFO7		75		27.14	409,035.0	3,354,491.5
CCFO5		50		45.95	409,035.0	3,354,491.5

Table 4-4
ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location East (m)	UTM Location North (m)
Natural Gas Firing						
CCNG1	8-Hour	100	1984	9.83	409,019.4	3,354,460.5
CCNG7		75		10.31	409,019.4	3,354,460.5
CCNG5		50		10.52	409,019.4	3,354,460.5
CCNG1		100	1985	7.49	409,019.4	3,354,460.5
CCNG7		75		8.64	409,019.4	3,354,460.5
CCNG5		50		9.64	409,019.4	3,354,460.5
CCNG1		100	1986	6.79	409,019.4	3,354,660.5
CCNG7		75		7.18	409,019.4	3,354,660.5
CCNG5		50		7.85	409,019.4	3,354,660.5
CCNG1		100	1987	7.64	409,019.4	3,354,360.5
CCNG7		75		8.55	409,019.4	3,354,360.5
CCNG5		50		9.72	409,019.4	3,354,360.5
CCNG1		100	1988	10.07	409,019.4	3,354,360.5
CCNG7		75		10.61	409,019.4	3,354,360.5
CCNG5		50		10.96	409,019.4	3,354,360.5
Fuel Oil Firing						
CCFO1	8-Hour	100	1984	9.32	409,019.4	3,354,460.5
CCFO7		75		9.99	409,019.4	3,354,460.5
CCFO5		50		17.53	409,019.4	3,354,460.5
CCFO1		100	1985	7.22	409,019.4	3,354,460.5
CCFO7		75		7.71	409,019.4	3,354,460.5
CCFO5		50		14.73	409,019.4	3,354,460.5
CCFO1		100	1986	6.01	409,019.4	3,354,660.5
CCFO7		75		6.50	409,019.4	3,354,660.5
CCFO5		50		11.82	409,019.4	3,354,660.5
CCFO1		100	1987	7.35	409,019.4	3,354,360.5
CCFO7		75		7.37	409,019.4	3,354,360.5
CCFO5		50		14.28	409,019.4	3,354,360.5
CCFO1		100	1988	9.40	409,019.4	3,354,360.5
CCFO7		75		10.03	409,019.4	3,354,360.5
CCFO5		50		<u>17.70</u>	409,019.4	3,354,360.5

Table 4-5
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10}

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
CC1	Annual	100	1984	0.04	406,585.0	3,356,491.5
CC7		75		0.06	409,019.4	3,354,676.7
CC5		50		0.09	409,019.4	3,354,676.7
CC1		100	1985	0.04	409,019.4	3,354,460.5
CC7		75		0.07	409,019.4	3,354,460.5
CC5		50		0.11	409,019.4	3,354,460.5
CC1		100	1986	0.05	409,019.4	3,354,676.7
CC7		75		0.07	409,019.4	3,354,676.7
CC5		50		0.12	409,019.4	3,354,676.7
CC1		100	1987	0.08	409,019.4	3,354,360.5
CC7		75		0.11	409,019.4	3,354,360.5
CC5		50		**0.17**	409,019.4	3,354,360.5
CC1		100	1988	0.06	409,019.4	3,354,360.5
CC7		75		0.09	409,019.4	3,354,360.5
CC5		50		0.13	409,019.4	3,354,360.5

Table 4-6
ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM_{10}

ISCST Operating Scenario Source Code	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	UTM Location East (m)	UTM Location North (m)
Natural Gas Firing						
CCNG1	24-Hour	100	1984	2.22	409,035.0	3,354,691.5
CCNG7		75		2.65	409,035.0	3,354,691.5
CCNG5		50		3.42	409,035.0	3,354,491.5
CCNG1		100	1985	2.10	409,019.4	3,354,460.5
CCNG7		75		2.91	409,019.4	3,354,460.5
CCNG5		50		4.05	409,019.4	3,354,460.5
CCNG1		100	1986	1.10	409,019.4	3,354,660.5
CCNG7		75		1.52	409,019.4	3,354,660.5
CCNG5		50		2.19	409,019.4	3,354,660.5
CCNG1		100	1987	1.37	409,019.4	3,354,360.5
CCNG7		75		2.03	409,019.4	3,354,360.5
CCNG5		50		2.74	409,019.4	3,354,360.5
CCNG1		100	1988	1.57	409,019.4	3,354,360.5
CCNG7		75		2.05	409,019.4	3,354,360.5
CCNG5		50		2.82	409,019.4	3,354,360.5
Fuel Oil Firing						
CCFO1		100	1984	3.49	409,035.0	3,354,691.5
CCFO7		75		4.24	409,035.0	3,354,691.5
FO5HI		50		4.15	409,035.0	3,354,691.5
FO5AV		50		4.23	409,035.0	3,354,691.5
FO5LO		50		4.27	409,035.0	3,354,691.5
CCFO1		100	1985	3.24	409,019.4	3,354,460.5
CCFO7		75		4.28	409,019.4	3,354,460.5
FO5HI		50		4.75	409,019.4	3,354,460.5
FO5AV		50		4.75	409,019.4	3,354,460.5
FO5LO		50		<u>4.76</u>	409,019.4	3,354,460.5
CCFO1		100	1986	1.44	409,019.4	3,354,660.5
CCFO7		75		2.15	409,019.4	3,354,660.5
FO5HI		50		2.39	408,535.0	3,354,291.5
FO5AV		50		2.38	409,019.4	3,354,660.5
FO5LO		50		2.39	409,019.4	3,354,660.5
CCFO1		100	1987	2.12	409,019.4	3,354,360.5
CCFO7		75		2.99	409,019.4	3,354,360.5
FO5HI		50		3.16	409,019.4	3,354,360.5
FO5AV		50		3.18	409,019.4	3,354,360.5
FO5LO		50		3.19	409,019.4	3,354,360.5
CCFO1		100	1988	2.37	409,019.4	3,354,360.5
CCFO7		75		3.02	409,019.4	3,354,360.5
FO5HI		50		3.19	409,019.4	3,354,360.5
FO5AV		50		3.20	409,019.4	3,354,360.5
FO5LO		50		3.20	409,019.4	3,354,360.5

Note: The Fuel Oil 50 percent load was modeled per High , Average, and Low temperature cases (High=95° F, Average=59°F, Low=20° F).

Electronic copies of the modeled inputs and outputs are presented in Attachment 5.

4.3.1 Comparison to PSD Significant Impact Levels and Preconstruction Monitoring Requirements

Table 4-7 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the preconstruction monitoring requirements. As Table 4-7 indicates, the Generating Station maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

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

Table 4-7
Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimis Monitoring Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimis Monitoring Level
NO_x	Annual	0.15	1	14
CO	1-Hour	72.55	2,000	--
	8-Hour	17.70	500	575
PM/PM_{10}	Annual	0.17	1	--
	24-Hour	4.76	5	10
VOC (Ozone)	N/A	31.8 tpy*	N/A	100 tpy

*Ozone preconstruction monitoring applicability based on an annualized Generating Station emission rate assuming 288 hours of distillate fuel oil firing and 8,472 hours of natural gas firing during base load (100 percent) conditions at 59° F ambient temperature.

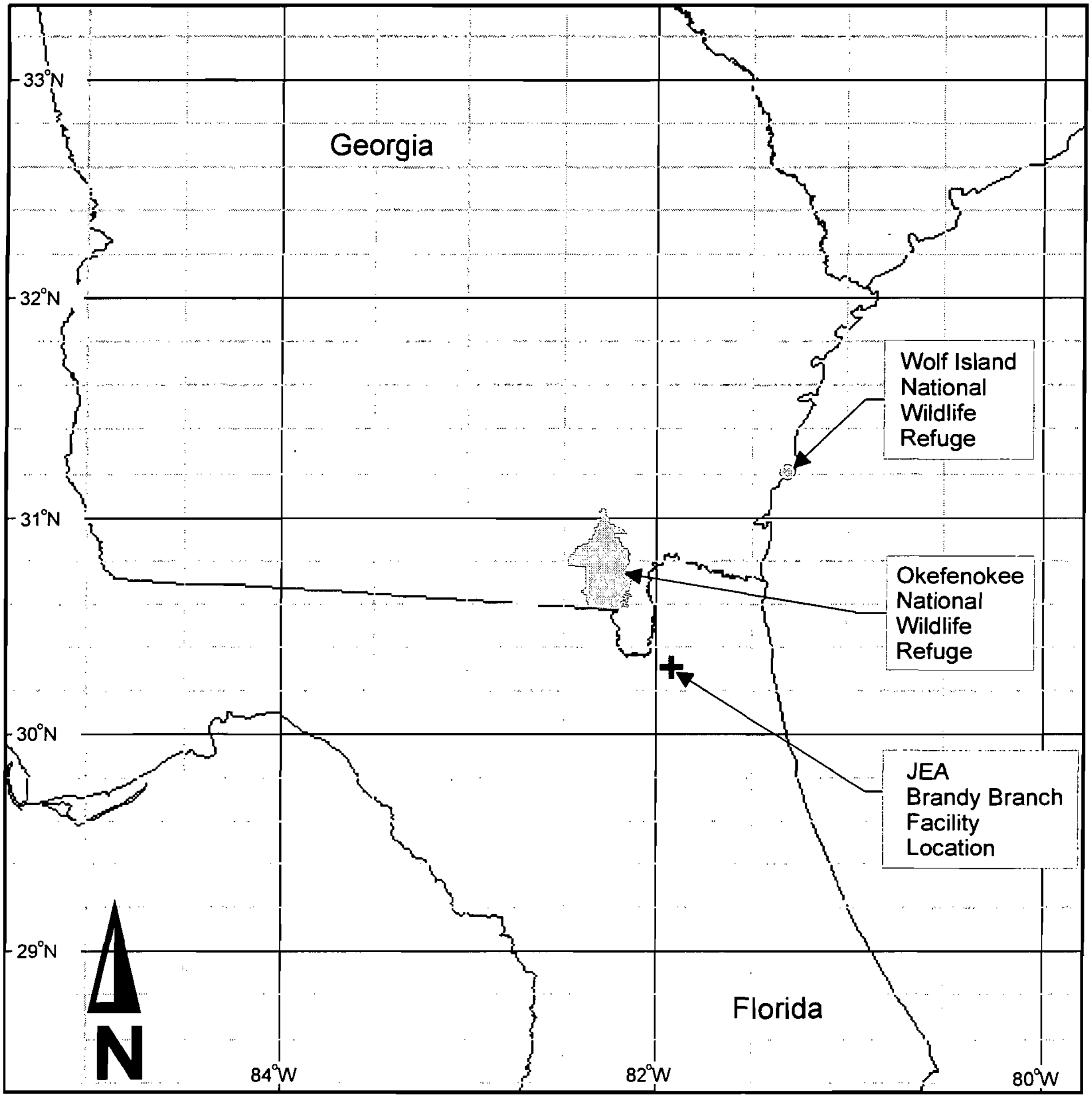
5.0 Additional and Class I Area Impact Analyses

As part of the air impact evaluation for the proposed facility, the Florida Department of Environmental Protection (FDEP) has requested that analyses of the proposed facility's affect on the Okefenokee National Wildlife Refuge (ONWR) and Wolf Island National Wildlife Refuge (WINWR) be performed. The ONWR and WINWR are Prevention of Significant Deterioration (PSD) Class I areas located in southeastern Georgia approximately 34 km north-northwest and 127 km north-northeast, respectively, of the proposed Generating Station site. Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in these air analyses are regional haze, deposition, and Class I Significant Impact Levels (SILs). Figure 5-1 presents the locations of the proposed Generating Station site with respect to the ONWR and WINWR.

The air analyses closely follow those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I & II* reports dated April 1993 and December 1998 (respectively), the *Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* dated October 1999, *EPA's Workbook for Plume Visual Impact Screening and Analysis* dated September 1988, as well as coordination with the FDEP who has communicated as necessary with the U.S. Fish and Wildlife Service (FWS) which is the Federal Land Manager (FLM) for both areas. This section 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.

5.1 Model Selection and Inputs

The Industrial Source Complex Short-Term (ISCST3 Version 00101) air dispersion model was used to characterize pollutant impacts at those portions of the Class I areas that lie within 50 km of the proposed site (i.e., ONWR). The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. The ISCST3 air dispersion model was used to determine the maximum ground level impacts of those PSD pollutants for which the Generating Station is significant and which have applicable significant impact levels for a Class I area (i.e., NO_x and PM_{10}).



Location of Brandy Branch Facility with Respect to Okefenokee and Wolf Island National Wildlife Refuges

Figure 5-1

Site wrt Class I areas.srf

The California Puff (CALPUFF, version 5.4) air modeling system was used to model the emissions associated with the two combined-cycle combustion turbines at the proposed facility and assess the AQRVs at those portions of ONWR and WINWR that lie beyond 50 km from the proposed site. 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 model was first used in a screening mode called CALPUFF 'Lite' to determine impacts onto the Class I areas. This method simplifies the modeling process while introducing a high level of conservatism. 'Lite' results which fell below the required thresholds of the previously listed AQRVs completed the demonstration of compliance for that particular AQRV and a refined CALPUFF analysis was not pursued. CALPUFF 'Lite' bypasses the need for the intensive meteorological processor, CALMET. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. For the refined analyses, the processed data produced from CALMET was input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF (including the 'Lite' and refined methodology) were used in a manner that is recommended by the IWAQM Phase I and II reports and Draft Phase I FLAG repor.

5.1.1. CALPUFF Model Settings

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

5.1.2 Building Wake Effects

The ISCST3 modeling as well as the screening and refined CALPUFF analyses include the proposed facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

5.1.3 Receptor Locations

The ISCST3 analysis used a set of 5 discrete receptors placed along the closest boundary of that portion of the ONWR that lies within 50 km of the proposed site. The ISCST3 receptors are shown in Figure 5-2.

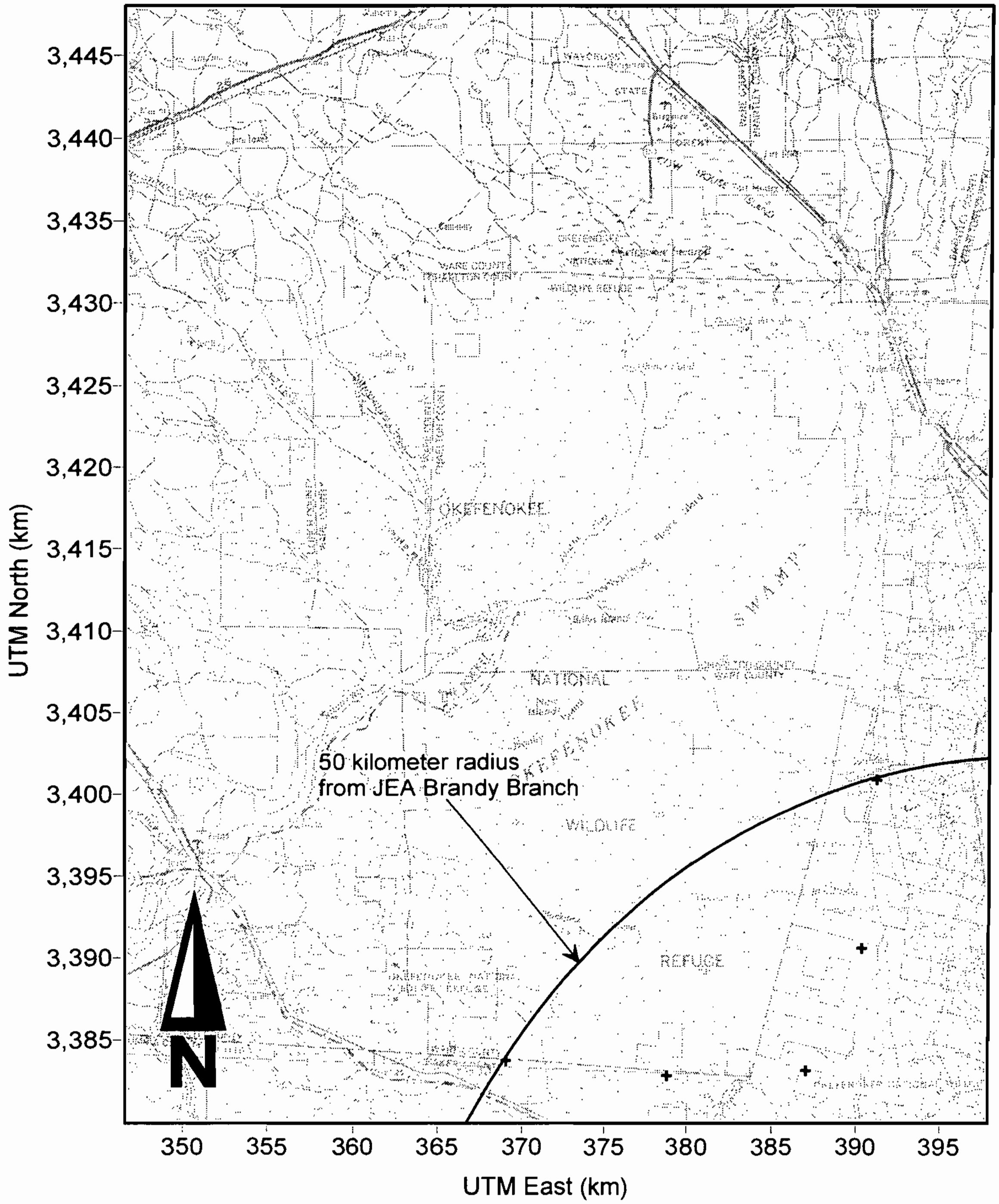
The CALPUFF 'Lite' analysis used rings of discrete Cartesian receptors located at distances equal to that of the closest and furthest boundaries of the Class I areas to the proposed Generating Station location. Specifically, the rings consist of receptor spacing of every 1-degree beginning at the appropriate distances from the proposed facility location. The receptor rings for ONWR and WINWR are shown in Figures 5-3 and 5-4, respectively.

The refined CALPUFF analysis used an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the ONWR. The same modeling grid as was used in the refined CALPUFF analysis for the previously submitted simple cycle project was again used here. Specifically, the array consists of receptor spacing of 2 km within the Class I area beginning at a distance of 50 km from the proposed Generating Station location and continuing to the farthest extent of the ONWR. The refined CALPUFF receptors on the ONWR are shown in Figure 5-5.

5.1.4 Meteorological Data Processing

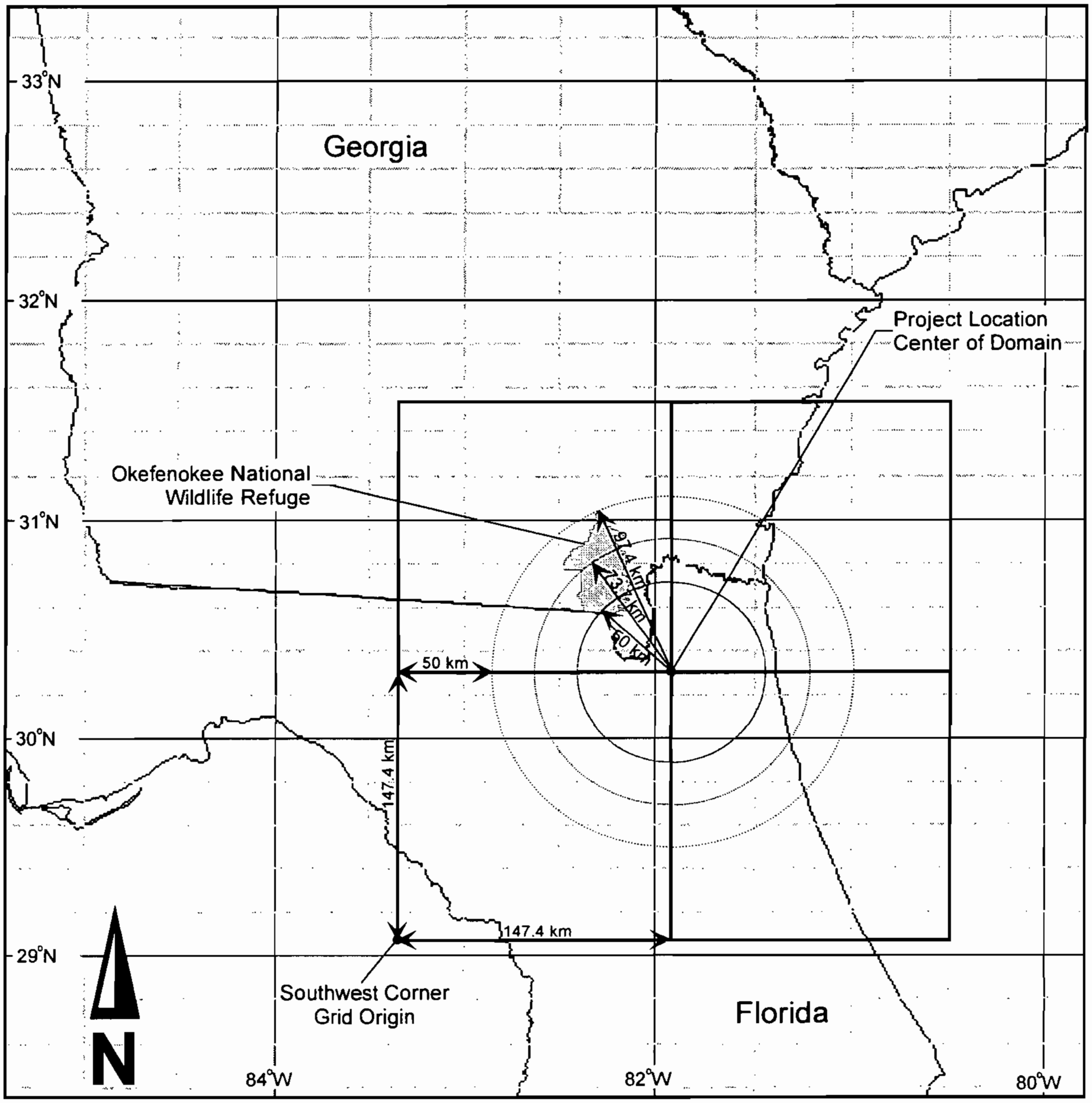
The meteorological data used in both the ISC modeling and the CALPUFF screening modeling consists of 5 years of surface observations (1984-1988) for Jacksonville, Florida extracted from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. These five years were combined with upper air, twice-daily mixing height data from Waycross, Georgia downloaded from the SCRAM BBS for the same five-year period. Both data sets were processed with PCRammet. However, the CALPUFF screening meteorological data was processed for wet deposition to give CALPUFF enough information to perform the Mesopuff II chemistry transformations. This type of processing allows CALPUFF to run in screening mode by providing extended meteorological variables such as surface friction, surface roughness, albedo, Bowen ratio, precipitation, etc. used in the atmospheric plume dispersion algorithms.

Table 5-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO2, SO4, NOx, HNO3, and NO3, and PM10
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	<u>CALPUFF 'Lite' – screening mode</u> 5 years of Jacksonville data (including precipitation) processed to include such parameters as the surface roughness, Bowen ratio, albedo, etc. <u>CALPUFF – refined mode</u> CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour SO4, NO3 and PM10 concentrations for the year. <u>Deposition:</u> Highest predicted 24-hour, SO2 and HNO3 values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Lite: Ozone = 80 ppb; Ammonia =10 ppb Refined: Ozone = 60 ppb; Ammonia = 3 ppb



ISCST3 Receptors for Class I SILs Modeling within 50 km of the Site

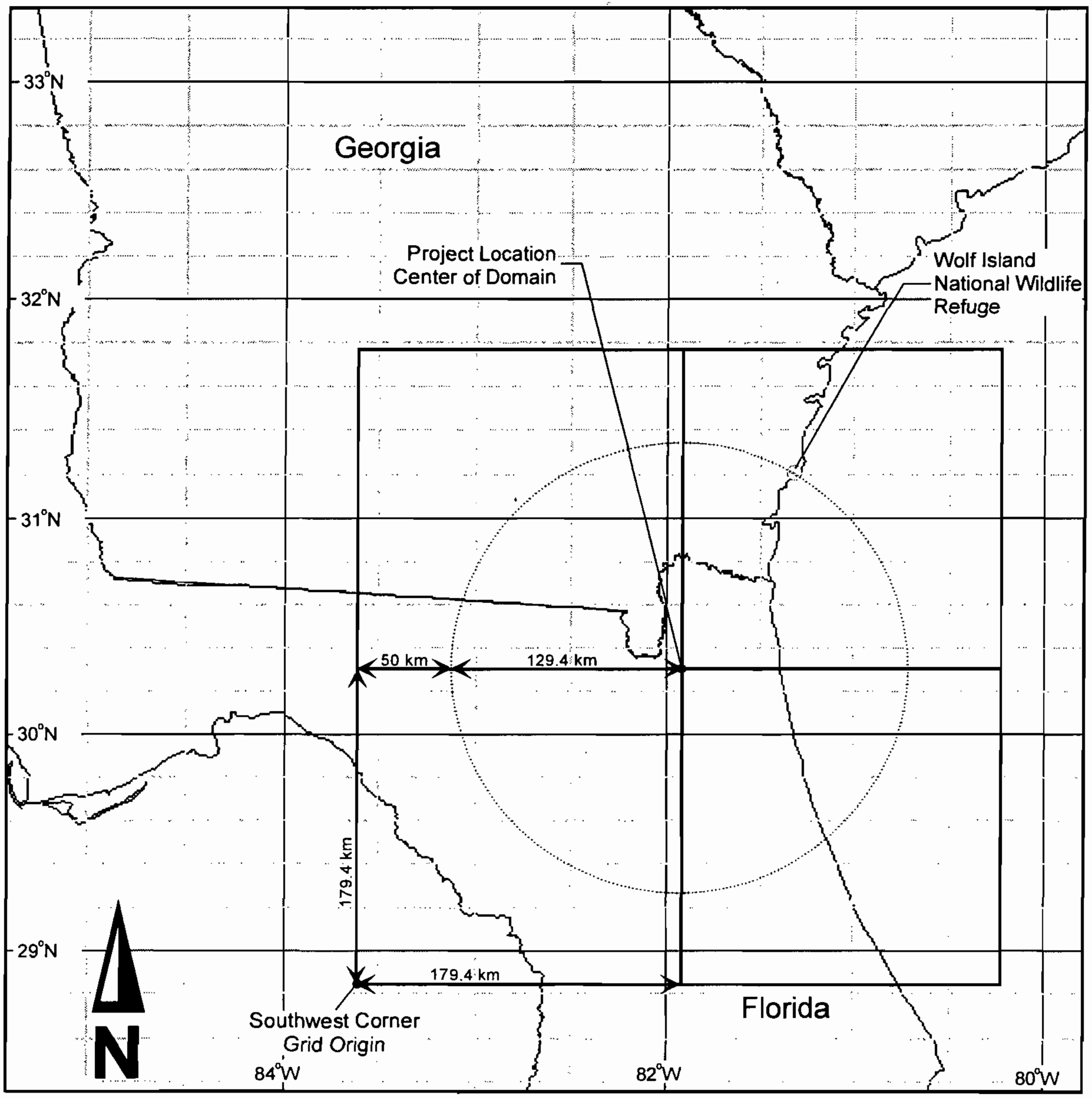
Figure 5-2



Okefenokee National Wildlife Refuge
CALPUFF Lite Receptor Rings

Figure 5-3

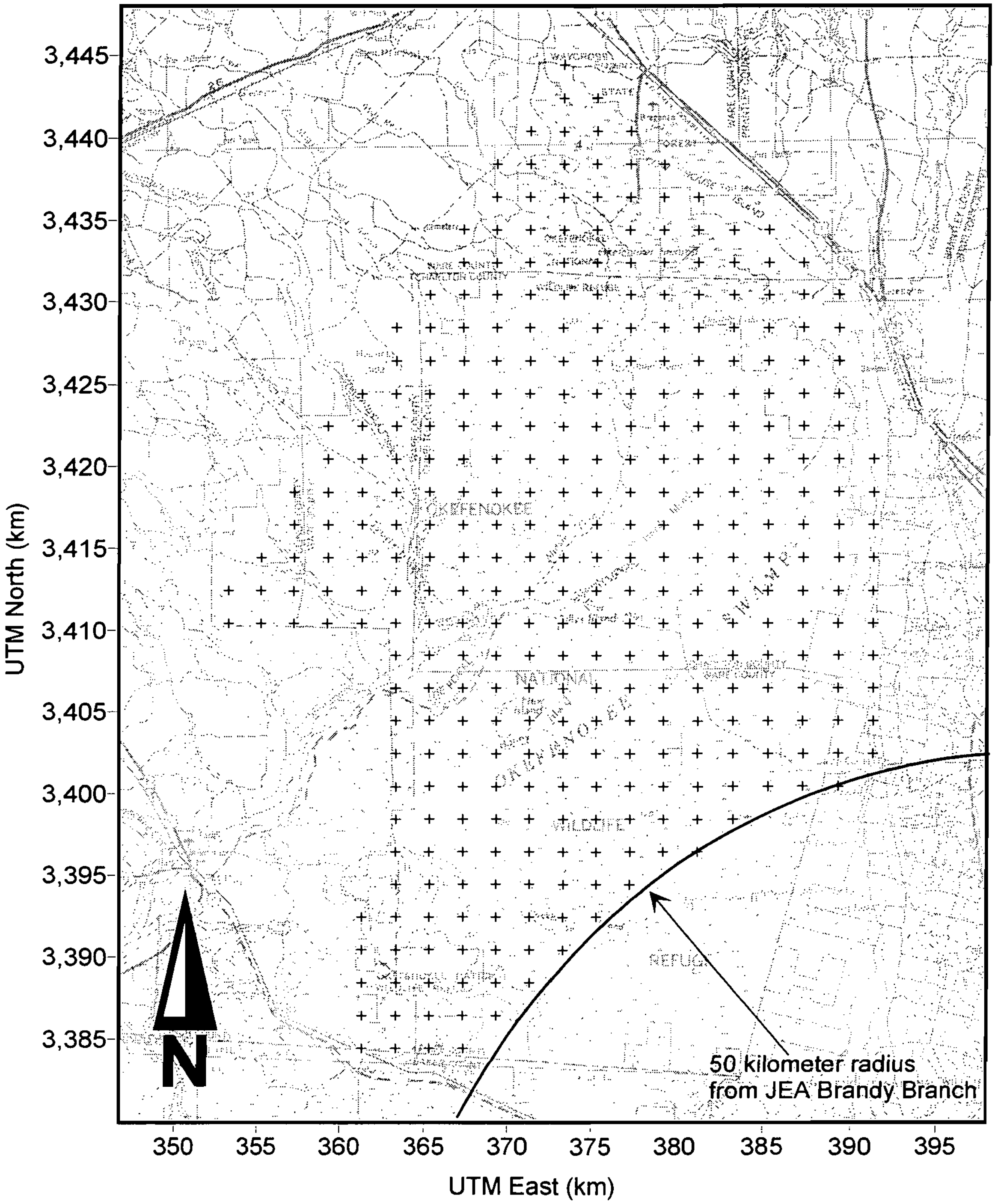
ONWR Calpuff Lite Receptors.srf



Wolf Island National Wildlife Refuge
CALPUFF Lite Receptor Ring

Figure 5-4

Wolf Island Calpuff Lite Receptors.srf



Dense 2 km Receptor Grid
for Refined CALPUFF Modeling

Figure 5-5

Oke Refined Receptors.srf

The refined CALPUFF analysis employed the California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) to develop the gridded parameter fields required for the refined AQRV modeling analysis. The following sections discuss the data used and processed in the CALMET model.

5.1.5 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, are contained in Table 5-2.

5.1.6 Modeling Domain

A rectangular modeling domain extending 325 km in the east-west (x) direction and 250 km in the north-south (y) direction was used for the refined modeling analysis. The boundary of the domain is represented by the dashed line in Figure 5-6. The southwest corner of the domain is the origin and is located at 29.25 N degrees latitude and 84 W degrees longitude. This location is in the northeastern Gulf of Mexico approximately 140 km due south of Tallahassee. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed Generating Station to the receptors at the ONWR with an 80-km buffer zone in each direction.

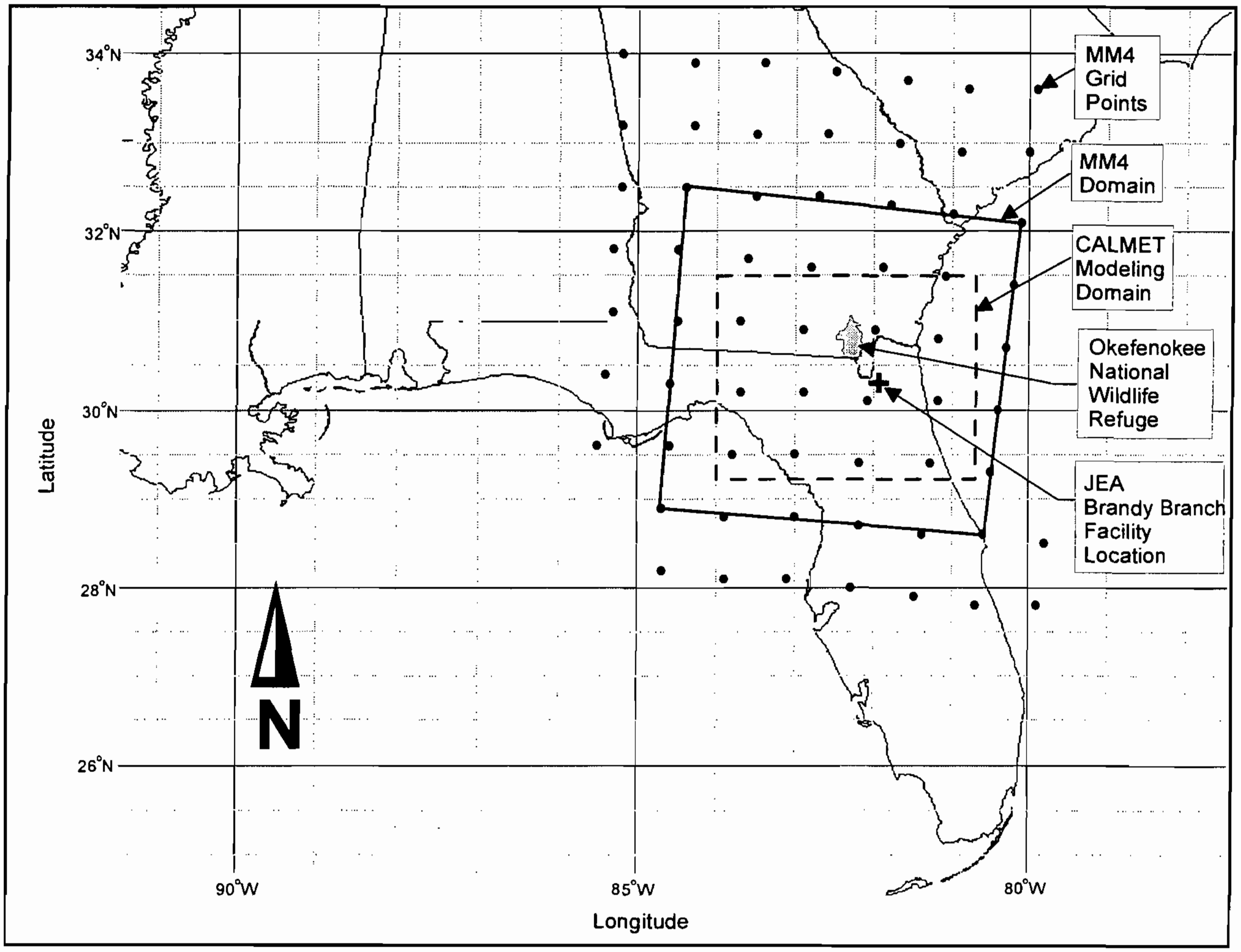
For the processing of meteorological and geophysical data, 65 grid cells were used in the x-direction and 50 grid cells were used in the y-direction. A 5-km grid spacing was used. The air modeling analysis was performed in the UTM coordinate system.

5.1.7 Mesoscale Model Data

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4

Table 5-2
CALMET Settings

PARAMETER	SETTING
Horizontal Grid Dimensions	325 by 250 km, 5 km grid resolution
Vertical Grid	8 layers
Weather Station Data Inputs	8 surface, 5 upper air, 35 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 6 x 6 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input



CALMET Domain

Domain.srf

Figure 5-6

data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

To apply a national MM4 dataset to the modeling domain, a sub-set domain was developed that fully enclosed the area of the modeling domain. The MM4 subset domain consisted of a 6 x 6-cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,13) to (54, 18). These data were processed to create a MM4.Dat file, for input to the CALMET model. The MM4 subset domain is represented by the solid line rectangle in Figure 5-6.

The MM4 data set used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

5.1.8 Surface Data Stations and Processing

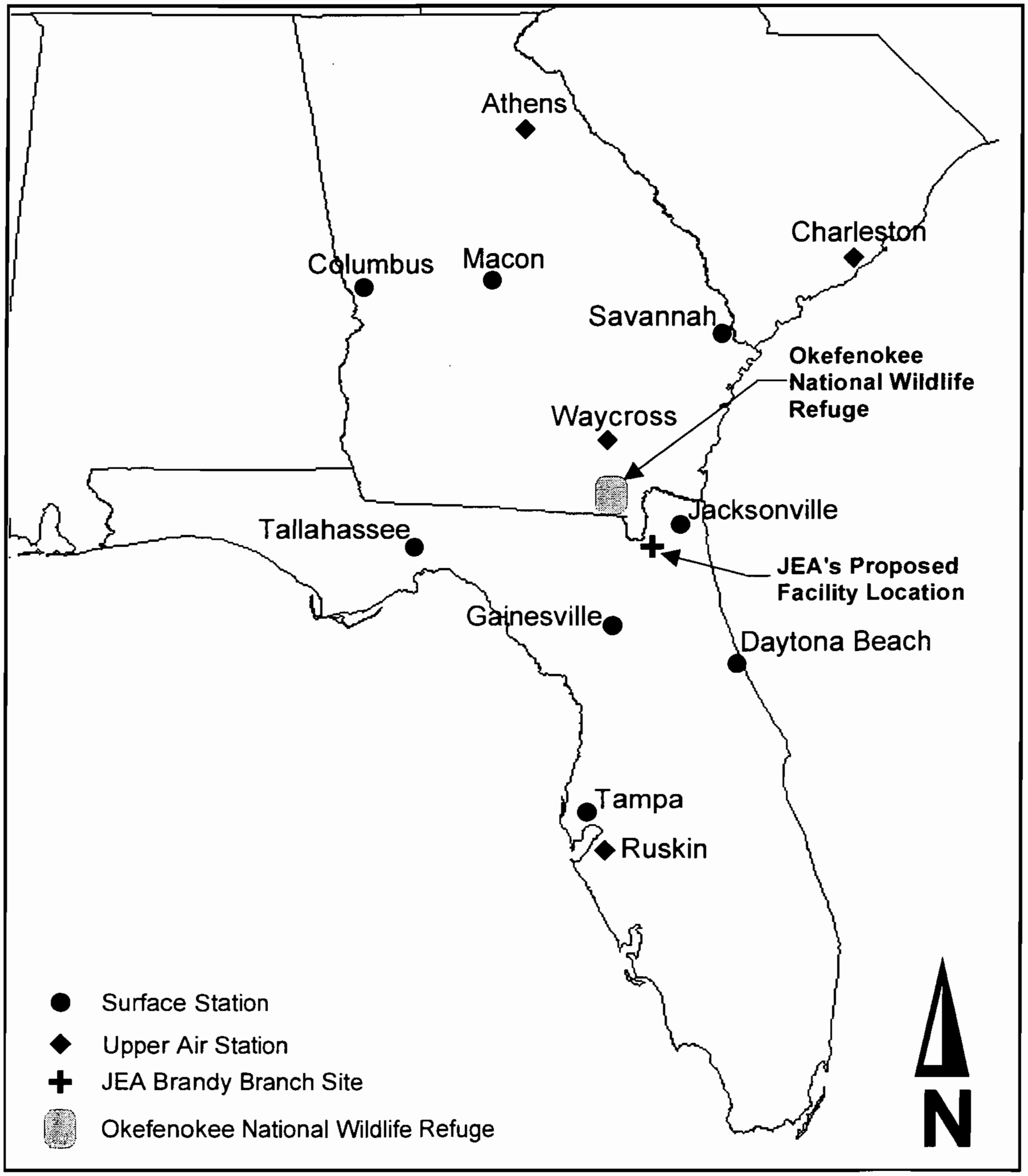
The surface station data processed for the refined CALPUFF analysis consisted of data from eight National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations for Jacksonville, Tallahassee, Gainesville, Tampa and Daytona Beach (FL) and Columbus, Macon and Savannah (GA). A summary of the surface station information and locations are presented in Table 5-3 and Figure 5-7, respectively. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions.

The weather station data for all stations but Gainesville was downloaded for the year 1990 from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. The surface data from Gainesville was processed from NCDC CD-144 format. The data was processed with the CALMET preprocessor utility program, SMERGE, to create one surface file, SURF.DAT.

Table 5-3
Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates			Anemometer Height (m)
			Easting (km)	Northing (km)	Zone	
Surface Stations						
Tampa, FL	TPA	12842	349.17	3094.25	17	6.7
Jacksonville, FL	JAX	13889	432.82	3374.19	17	6.1
Daytona Beach, FL	DAB	12834	495.14	3228.09	17	9.1
Tallahassee, FL	TLH	93805	173.04[a]	3363.99	16	7.6
Columbus, GA	COL	93842	112.57[a]	3599.35	16	9.1
Macon, GA	MCN	03813	251.58	3620.93	17	7.0
Savannah, GA	SAV	03822	481.13	3555.03	17	9.1
Gainesville, FL	GNV	12816	377.43	3284.16	17	6.7
Upper Air Stations						
Ruskin, FL	TBW	12842	361.95	3064.55	17	NA
Waycross, GA	AYS	13861	366.68	3457.95	17	NA
Athens, GA	AHN	13873	285.91	3758.83	17	NA
Charleston, SC	CHS	13880	590.42	3640.42	17	NA
Apalachicola, FL	AQQ	12832	110.22	3290.65	17	NA

[a] Equivalent Coordinate for Zone 17



National Weather Service
Meteorological Surface & Upper Air Stations
Used in the CALMET Model

Figure 5-7

Met Stations.srf

5.1.9 Upper Air Data Stations and Processing

The analysis included five upper air NWS stations located in Ruskin and Apalachicola (FL), Athens and Waycross (GA), and Charleston (SC). Data for these stations was obtained from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the READ62 utility program for input to CALMET. The data and locations for the upper air stations are presented in Table 5-3 and Figure 5-7, respectively.

5.1.10 Precipitation Data Stations and Processing

Precipitation data was processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations located in southern Georgia and northern Florida. Data for 35 stations within or just beyond the modeling domain (dashed rectangular box in Figure 5-6) were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were used to process the data into the format for the Precip.Dat file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table 5-4.

5.1.11 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain were obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data was extracted for the modeling domain grid using the utility extraction program LCELEV. Land-use data was obtained from the USGS GIS.DAT which is based on the ARM3 data. The resolution of the GIS.DAT file is one-eighth of a degree in the east-west direction and one-twelfth of a degree in the north-south direction. Land-use values for the domain grid were obtained with the utility program CAL-LAND. Other parameters processed for the modeling domain by CAL-LAND include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once processed, all of the land-use parameters were combined with the terrain information into a GEO.DAT file for input to CALMET. The land-use parameter values were based on annual averaged values.

Table 5-4
Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinates		
Florida		Easting (km)	Northing (km)	Zone
Branford	80975	315.61	3315.96	17
Bristol	81020	113.72[a]	3366.47	16
Brooksville 7 SSW	81048	358.03	3149.55	17
Cross city 2 WNW	82008	290.27	3281.75	17
Daytona Beach WSO AP	82158	495.14	3228.09	17
Deland 1 SSE	82229	470.78	3209.66	17
Dowling Park 1 W	82391	283.51	3348.42	17
Gainesville 11 WNW	83322	354.85	3284.43	17
Inglis 3 E	84273	342.63	3211.65	17
Jacksonville WSO AP	84358	434.27	3372.40	17
Lakeland	84797	409.87	3099.18	17
Lisbon	85076	423.59	3193.26	17
Lynne	85237	409.26	3230.30	17
Marineland	85391	479.19	3282.03	17
Melbourne WSO	85612	534.38	3109.97	17
Monticello 3 W	85879	220.17	3381.29	17
Orlando WSO McCoy	86628	468.99	3146.88	17
Panacea 3 s	86828	172.45[a]	3319.61	16
Raiford State Prison	87440	385.93	3326.55	17
Saint Leo	87851	376.48	3135.09	17
Tallahassee WSO AP	88758	173.04[a]	3363.99	16
Woodruff Dam	89795	124.29[a]	3399.94	16

Table 5-4 (Continued) Hourly Precipitation Stations Used in the CALPUFF Analysis				
Georgia				
Abbeville 4 S	90010	281.84	3535.69	17
Bainbridge Intl Paper Co	90586	144.85[a]	3409.59	16
Brunswick	91340	452.34	3447.98	17
Coolidge	92238	226.34	3434.77	17
Doles	92728	226.73	3510.59	17
Edison	93028	135.13[a]	3494.43	16
Fargo	93312	349.92	3395.35	17
Folkston 3 SW	93460	401.13	3407.69	17
Hazlehurst	94204	348.49	3526.08	17
Jesup	94671	416.21	3498.08	17
Pearson	96879	325.50	3464.09	17
Richmond Hill	97468	468.92	3535.69	17
Valdosta 4 NW	98974	276.90	3416.95	17
[a] Equivalent Coordinate for Zone 17				

5.1.12 Facility Emissions

Performance data for the combustion turbines was based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates considering three representative ambient temperatures at base load operation for natural gas and distillate fuel oil firing were used for the pollutants modeled. The emission rates and stack parameters are listed in Table 5-5.

5.2 Class I Analyses

The preceding model inputs and settings for the ISCST3 and CALPUFF modeling system (both screening and refined mode) were used to complete the Class I analyses on the ONWR and WINWR, including visibility/regional haze, deposition (both sulfate and nitrate), and Class I SILs. The following analyses were performed as described below regardless of the modeling methodology (i.e., ISCST3 or CALPUFF - screening or refined modeling).

5.3 Visiblity/Regional Haze Analyses

A visibility analysis was performed for that portion of the ONWR that lies within 50 km of the proposed site. The VISCREEN model was used to assess the visual impact of the proposed facility onto that portion of the ONWR Class I area. Regional haze analyses were performed, using the CALPUFF modeling system, for those portions of the Class I areas that lie beyond 50 km from the proposed site for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

Table 5-5
Stack Parameters and Pollutant Emissions used in the CALPUFF Analysis

Stack No.	Easting (m)	Northing (m)	Stack Height	Stack Diameter	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
							NO_x	SO_2	PM_{10}
3	408,713	3,354,531	57.9	5.49	21.28	402.6	15.04	13.78	5.67
2	408,774	3,354,531	57.9	5.49	21.28	402.6	15.04	13.78	5.67

*Assumes operation on distillate fuel oil will yield worst-case impacts.

5.3.1 Visibility

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

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

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

bext(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 the percentage change in extinctions. The change is defined as:

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

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 change in b_{extb}, or; percent change in extinction. Based on the IWAQM Phase II guidance, if the change in extinction is less than 5 percent, no further analysis is required.

5.3.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual ranges for the ONWR and WINWR were obtained from Bud Rolefson of the United State Fish and Wildlife Service (USFWS). Mr. Rolefson, as the Federal Land Manager of the ONWR and WINWR, supplied the values used in the analyses. The average relative humidity factor for each species' worst day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity was obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) were then used to determine the average relative humidity factor for that day (24-hour period).

5.3.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis (both screening and refined) followed the recommendations contained in the IWAQM Phase I and II Summary Reports and Recommendations for Modeling Long Range Transport Impacts, (EPA, 4/93 and 12/98). Table 5-6 summarizes the IWAQM recommendations. The methodology below was used to compute the results of the regional haze analysis. A typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain maximum 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   - $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   - $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   - NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   - NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   $b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 1 \times PM_{10}$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) obtained from Mr. Bud Rolefson of the USFWS:

b_{extb} = 3.912 / Visual range (km)

6. Compute the change in extinction coefficients:
   in terms of percent change of visibility:
   $\Delta\% = (b_{exts} / b_{extsb}) \times 100$

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

5.3.4 Visibility/Regional Haze Results

The VISCREEN plume visual impact screening model was used with default worst-case Level-1 visual screening parameters using the maximum estimated emission rates of NO_x and PM_{10} for distillate oil firing as presented in Table 5-5. The model output indicates the possibility of an exceedance of the conservative Level-1 threshold values. Thus, a more refined Level-2 analysis was employed. The Level-2 analysis used more representative meteorological conditions and plume characteristics. That is, the Jacksonville meteorological data was analyzed for the average meteorological conditions (i.e., wind speed of 3.53 m/s and a stability of D) rather than the conservative Level-1 values of 1 m/s and stability of F. Also, the particle size of the plume was modeled at 10 µm. Results of the Level-2 visual screening analysis indicate that the conservative criteria are not exceeded. Therefore, further analyses to quantify the extent of any reductions in visibility due to the proposed Generating Station are not warranted based on the results of the Level-2 visual impairment analysis. The report output of the VISCREEN model for both the Level-1 and Level-2 analyses are included in Attachment 6.

Table 5-6 **Outline of IWAQM Refined Modeling Analyses Recommendations***	
Meteorology	<u>CALPUFF 'Lite'</u> 5 years of the closest surface station and upper air station. <u>Refined CALPUFF</u> 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 sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	<u>CALPUFF 'Lite'</u> Rings of receptors spaced every 1-degree. <u>Refined CALPUFF</u> Within Class I area(s) of concern.
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, NO_3, and PM_{10} values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the supplied background extinction.
**IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 12/98).*	

The CALPUFF air modeling system was used to assess regional haze impacts onto the Class I areas beyond 50 km from the proposed Generating Station. Tables 5-7 and 5-8 summarize the species' maximum impacts and predicted worst days for the 'Lite' visibility analyses for ONWR and WINWR, respectively. For each worst day, the hourly relative humidities and corresponding hourly relative humidity factors [f(RH)] were averaged and appear in the Tables. The maximum predicted change in extinction due to the proposed Generating Station operation for each Class I area is also presented. The 'Lite' results indicate that the change in extinction due to the operation of the proposed Generating Station on the ONWR is greater than the 5 percent change allowed, while the change at WINWR is less than the 5 percent threshold (i.e., no further regional haze analysis is warranted for WINWR). Since the ONWR CALPUFF 'Lite' results indicate the possibility of an exceedance of the extinction threshold, a refined CALPUFF modeling analysis (as described in previous sections) was performed for ONWR. The results from the refined CALPUFF modeling at ONWR are presented in Table 5-9. The maximum predicted change is 2.83 percent. This impact is below the 5 percent change criteria indicating that the proposed facility operation does not adversely impact the existing regional haze at the ONWR. The regional haze calculations, using the output from CALPUFF, are included in Attachment 7.

5.4 Deposition Analysis

Deposition analyses were performed for the ONWR and WINWR for both sulfates and nitrates. The analyses followed those procedures and methodologies set forth in the IWAQM Phase I Report. Specifically, deposition analyses were performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned (including output of both dry and wet deposition).
2. Perform individual CALPOST post-processor runs to output the maximum 24-hour average wet and dry deposition impacts of SO_2 and HNO_3 in µg/m2/s units.
3. Apply the appropriate scaling factors to the above CALPOST runs to account for the conversion of micrograms to kilograms, square meters to hectares (ha), seconds to hours, and hours to a day. Thus, the CALPOST results are output in kg/hectare.
4. For sulfate deposition, sum the results of both the wet deposition and dry deposition values for the SO_2 CALPOST runs.
5. For nitrate deposition, sum the results of both the wet deposition and dry deposition values for the HNO_3 CALPOST runs.

The results of the sulfate and nitrate deposition analyses for ONWR and WINWR are presented in Table 5-10. Since there are no published threshold values for comparison, the values presented in the Table are for review and evaluation by the FLM of the affected Class I areas.

5.5 Class I Impact Analysis

Ground-level impacts (in µg/m3) onto to the ONWR and WINWR were calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) for each applicable averaging period (i.e., NO_x – Annual, PM_{10} – Annual, and PM_{10} – 24 hour). The ISCST3 air dispersion model was used for that portion of the ONWR that lies with 50 km of the proposed site. The CALPUFF air modeling system was used for those portions of ONWR and WINWR that lie beyond 50 km. As in the regional haze analyses, CALPUFF was used in the screening mode ('Lite') for WINWR and refined mode for ONWR. The results of this analysis, presented in Table 5-11, are compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. There are no exceedances of the Class I SILs. Therefore, no further analyses are warranted.

5.6 Commercial, Residential, and Industrial Growth

The Generating Station is at the new electrical power generating station Brandy Branch Facility near Baldwin City within Duval County. There will be an increase in the local labor force during the construction phase of the Generating Station, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the Generating Station.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by the Generating Station will not have a significant effect upon the industrial growth in the immediate area considering that the electrical generating capacity will be supplied to the JEA grid as opposed to a nearby industrial host. Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of new, permanent jobs which will be created by the Generating Station is estimated to be six. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the proposed facility will be very small, compared to the overall population size of the surrounding area.

Table 5-7
CALPUFF 'Lite' Analysis Results on ONWR

Item	Predicted Worst Days (Year – Day)		
	1985 – 333	1987 – 357	1987 – 357
Maximum Predicted Conc. ($\mu g/m^3$)			
SO_4	0.009554	0.064811	0.064811
NO_3	0.037555	0.119000	0.119000
PM_{10}	0.237610	0.141430	0.141430
Average Relative Humidity Factor[a]	6.0	5.7	5.7
Background Visual Range[b], Vr (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (Mm^{-1})	60.2	60.2	60.2
Source Extinction Coeff. (b_{exts}) (Mm^{-1})			
$(NH_4)_2SO_4$	0.236462	1.523869	1.523869
NH_4NO_3	0.872027	2.625021	2.625021
PM_{10}	0.237610	0.141430	0.141430
Total (b_{exts}) (Mm^{-1})	1.35	4.29	4.29
Percent Change (%)	2.24	7.13	7.13

[a]Computed from Jacksonville RH data.
[b]Provided by U.S. Fish and Wildlife Service.

Table 5-8

CALPUFF 'Lite' Analysis Results on WINWR

Item	Predicted Worst Days (Year – Day)		
	1984 – 246	1984 – 362	1988 – 345
Maximum Predicted Conc. ($\mu g/m^3$)			
SO_4	0.014663	0.005798	0.036017
NO_3	0.016575	0.090114	0.033520
PM_{10}	0.125220	0.033451	0.067145
Average Relative Humidity Factor[a]	4.9	3.4	5.1
Background Visual Range[b], Vr (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (Mm^{-1})	60.2	60.2	60.2
Source Extinction Coeff. (b_{exts}) (Mm^{-1})			
$(NH_4)_2SO_4$	0.296376	0.081317	0.757708
NH_4NO_3	0.314312	1.185720	0.661584
PM_{10}	0.125220	0.033451	0.067145
Total (b_{exts}) (Mm^{-1})	0.74	1.30	1.49
Percent Change (%)	1.22	2.16	2.47

[a]Computed from Jacksonville RH data.
[b]Provided by U.S. Fish and Wildlife Service.

Table 5-9
CALPUFF Refined Analysis Results on ONWR

Item	Predicted Worst Days (Year – Day)		
	1990 – 007	1990 – 157	1990 – 157
<u>Maximum Predicted Conc. (μg/m³)</u>			
SO_4	0.016911	0.038374	0.038374
NO_3	0.034835	0.019226	0.019226
PM_{10}	0.064405	0.224280	0.224280
Average Relative Humidity Factor[a]	8.0	3.4	3.4
Background Visual Range[b], Vr (km)	65	65	65
Background Extinction Coeff. (b_{extb}) (Mm^{-1})	60.2	60.2	60.2
<u>Source Extinction Coeff. (b_{exts}) (Mm^{-1})</u>			
$(NH_4)_2SO_4$	0.5577	0.5386	0.538195
NH_4NO_3	1.0774	0.2526	0.252976
PM_{10}	0.0644	0.2243	0.224280
Total (b_{exts}) (Mm^{-1})	1.70	1.02	1.02
Percent Change (%)	2.83	1.69	1.69

[a]Computed from Jacksonville RH data.
[b]Provided by U.S. Fish and Wildlife Service.

Table 5-10
Sulfate and Nitrate Deposition Results

Class I Area	Dry Deposition[a] (kg/hectare)		Wet Deposition[a] (kg/hectare)		Total Deposition[a] (kg/hectare)	
	SO_2	HNO_3	SO_2	HNO_3	SO_2	HNO_3
Okefenokee[b]	0.0030	0.0011	0.0052	0.0026	0.0082	0.0037
Wolf Island[c]	0.0005	0.0002	0.0038	0.0009	0.0043	0.0011

[a]Results are 24-hour average values.
[b]Okefenokee results were obtained using refined CALPUFF modeling due to the outcome of the regional haze analysis necessitating its use.
[c]Wolf Island results were obtained using screening CALPUFF modeling (i.e., 'Lite').

Table 5-11
Class I Significant Impact Level (SIL) Results

Class I Area	NO_x – Annual		PM_{10} – Annual		PM_{10} – 24 hour	
	Impact ($\mu g/m^3$)	SIL[a] ($\mu g/m^3$)	Impact ($\mu g/m^3$)	SIL[a] ($\mu g/m^3$)	Impact ($\mu g/m^3$)	SIL[a] ($\mu g/m^3$)
Okefenokee[b]	0.012	0.1	0.009	0.16	0.213	0.32
Okefenokee[c]	0.009	0.1	0.009	0.16	0.224	0.32
Wolf Island[d]	0.005	0.1	0.005	0.16	0.125	0.32

[a]Class I Significant Impact Levels calculated as 4 percent of the Class I Increment Levels.

[b]For that portion of Okefenokee within 50 km of the proposed Generating Station location, the ISCST3 air dispersion model was used to obtain impacts.

[c]For that portion of Okefenokee beyond 50 km from the proposed Generating Station location, the CALPUFF air modeling system was used in refined mode to obtain impacts.

[d]Wolf Island lies beyond 50 km from the proposed Generating Station location. As such, the CALPUFF air dispersion modeling system was used in the screening mode (i.e., 'Lite') to obtain impacts.

5.7 Vegetation and Soils

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

The NAAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, ambient concentrations of NO_2, SO_2, CO, and PM/PM_{10} below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

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

Attachment 1
Performance Data

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liqu
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,5
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,0
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,1
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,54
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,4
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,91
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,72

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	58.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	54.	44.	35.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen	72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen	12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide	3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water	10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)									
Load Condition		BASE	*75%*	*50%*	*25%*	*BASE*	*75%*	*50%*	*25%*
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liq
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18.5
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45.5
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,0
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,54
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,9
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,6
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27.1
EMISSIONS									
NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	77.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	60.	48.	38.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen		74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen		12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide		3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water		8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS		
Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liqu
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18.5
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,2
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,69
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,66
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,24
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28.73

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	80.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	64.	51.	40.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat r correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,550	173,260	175,940	192,770	187,860	193,000	192,430
Ambient Temperature, F	95.0	95.0	95.0	95.0	59.0	59.0	20.0
Ambient Temperature, C	35.0	35.0	35.0	35.0	15.0	15.0	(6.7)
Ambient Relative Humidity, %	60.0	60.0	60.0	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
Atmospheric Pressure, bar(a)	1.013	1.013	1.013	1.013	1.013	1.013	1.013
CTG Compressor Inlet Dry Bulb Temperature, F	95.0	95.0	84.5	84.5	59.0	59.0	20.0
CTG Compressor Inlet Temperature, C	35.0	35.0	29.2	29.2	15.0	15.0	(6.7)
CTG Compr. Inlet Relative Humidity, %	60.1	60.1	92.6	92.6	60.2	60.2	60.3
CTG Inlet Air Conditioning Included?	No	No	Yes (Evap. Cooler)	Yes (Evap. Cooler)	No	No	No
Inlet Loss, in. H2O	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Inlet Loss, mm. H2O	88.9	88.9	88.9	88.9	88.9	88.9	88.9
Exhaust Loss, in. H2O	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Exhaust Loss, mm. H2O	381.0	381.0	381.0	381.0	381.0	381.0	381.0
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	100%	100%	100%
Gross CTG Output, kW	148,500	148,500	155,290	155,290	170,900	170,900	184,020
Gross CTG Heat Rate, Btu/kWh (LHV)	9,803	9,803	9,684	9,684	9,406	9,406	9,347
Gross CTG Heat Rate, KJ/KWh (LHV)	10,342	10,342	10,217	10,217	9,924	9,924	9,861
Gross CTG Heat Rate, kJ/kWh (HHV)	10,887	10,887	10,755	10,755	10,446	10,446	10,380
Gross CTG Heat Rate, KJ/KWh (HHV)	11,486	11,486	11,347	11,347	11,021	11,021	10,951
CTG Heat Input, MBtu/h (LHV)	1,455.7	1,455.7	1,503.8	1,503.8	1,607.5	1,607.5	1,719.9
CTG Heat Input, GJ/h (LHV)	1,535.8	1,535.8	1,586.5	1,586.5	1,696.0	1,696.0	1,814.6
CTG Heat Input, MBtu/h (HHV)	1,616.7	1,616.7	1,670.1	1,670.1	1,785.3	1,785.3	1,910.2
CTG Heat Input, GJ/h (HHV)	1,705.7	1,705.7	1,762.0	1,762.0	1,883.6	1,883.6	2,015.4
CTG Water Injection Flow, lb/h	0	0	0	0	0	0	0
CTG Water Injection Flow, kg/h	0	0	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0	0
CTG Steam Injection Flow, kg/h	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
CTG Exhaust Flow, lb/h	3,254,000	3,254,000	3,331,310	3,331,310	3,542,000	3,542,000	3,801,000
CTG Exhaust Flow, kg/h	1,475,990	1,475,990	1,511,057	1,511,057	1,606,624	1,606,624	1,724,105
CTG Exhaust Temperature, F	1,151	1,151	1,143	1,143	1,123	1,123	1,068
CTG Exhaust Temperature, C	621.7	621.7	617.2	617.2	606.1	606.1	586.7
CTG Exhaust Enthalpy, Btu/lb	284.13	284.13	282.51	282.51	281.91	281.91	280.56
CTG Exhaust Enthalpy, kJ/lb	299.77	299.77	298.06	298.06	297.43	297.43	296.01
CTG Exhaust Enthalpy Reference Temperature, F	95	95	95	95	59	59	20
CTG Exhaust Enthalpy Reference Temperature, C	35.0	35.0	35.0	35.0	15.0	15.0	(6.7)
CTG Exhaust Heat, MBtu/h	924.6	924.6	941.1	941.1	998.5	998.5	1,066.4
CTG Exhaust Heat, GJ/h	975.5	975.5	992.9	992.9	1,053.5	1,053.5	1,125.1
CTG Exhaust Heat/CTG Output, kW/kW	182.5%	182.5%	177.6%	177.6%	171.2%	171.2%	169.8%
Total CTG Fuel Flow, lb/h	70410	70410	72730	72730	77750	77750	83190
CTG Fuel Temperature, F	365	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,675	20,675	20,675	20,675	20,675	20,675	20,675
CTG Fuel LHV, kJ/lb	48,090	48,090	48,090	48,090	48,090	48,090	48,090
CTG Fuel HHV, Btu/lb	22,962	22,962	22,962	22,962	22,962	22,962	22,962
CTG Fuel HHV, kJ/lb	53,410	53,410	53,410	53,410	53,410	53,410	53,410
HHV/LHV Ratio	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106
CTG Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%
H2	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%
N2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,560	173,260	175,940	192,770	187,860	193,000	192,430
Combustion Turbine Exhaust Emissions							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.91%	0.91%	0.91%	0.91%	0.93%	0.93%	0.94%
CO2	3.79%	3.79%	3.82%	3.82%	3.88%	3.88%	3.88%
H2O	10.79%	10.79%	11.20%	11.20%	8.72%	8.72%	7.96%
N2	72.57%	72.57%	72.27%	72.27%	74.25%	74.25%	74.85%
O2	11.93%	11.93%	11.80%	11.80%	12.21%	12.21%	12.37%
SO2	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%
NOx, ppmvd @15% O2	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd @ 15% O2	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd	11.44	11.44	11.58	11.58	11.44	11.44	11.34
NOx, ppmvw (wet - uncorrected exhaust gas)	10.20	10.20	10.28	10.28	10.44	10.44	10.44
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
Additonal Percent Margin Included in NOx Emissions below	5%	5%	5%	5%	5%	5%	5%
NOx, lb/h as NO2	54.03	54.03	55.91	55.91	59.97	59.97	64.38
NOx, lb/MBtu (LHV)	0.04	0.04	0.04	0.04	0.04	0.04	0.04
NOx, lb/MBtu (HHV)	0.03	0.03	0.03	0.03	0.03	0.03	0.03
NOx, mg/Nm3 as NO2 (dry, 15% O2)	18.38	18.38	18.41	18.41	18.48	18.48	18.54
NOx, mg/Nm3 as NO2 (dry, 15% O2)	18.38	18.38	18.41	18.41	18.48	18.48	18.54
NOx, mg/Nm3 as NO2 (dry)	23.36	23.36	23.69	23.69	23.48	23.48	23.36
NOx, mg/Nm3 as NO2 (wet - uncorrected exhaust flow)	20.84	20.84	21.03	21.03	21.43	21.43	21.50
NOx, mg/MJ (LHV)	15.96	15.96	15.98	15.98	16.04	16.04	16.09
NOx, mg/MJ (HHV)	14.37	14.37	14.39	14.39	14.44	14.44	14.49
CO, ppmvd @ 15% O2	11.80	11.80	11.66	11.66	11.81	11.81	11.90
CO, ppmvd @ 15% O2	11.80	11.80	11.66	11.66	11.81	11.81	11.90
CO, ppmvd	15.00	15.00	15.00	15.00	15.00	15.00	15.00
CO, ppmvw (wet - uncorrected exhaust gas)	13.38	13.38	13.32	13.32	13.69	13.69	13.81
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in CO Emissions below	5%	5%	5%	5%	5%	5%	5%
CO, lb/h	45.53	45.53	46.47	46.47	50.29	50.29	54.26
CO, lb/MBtu (LHV)	0.03	0.03	0.03	0.03	0.03	0.03	0.03
CO, lb/MBtu (HHV)	0.03	0.03	0.03	0.03	0.03	0.03	0.03
CO, mg/Nm3 (wet - uncorrected exhaust flow)	17.56	17.56	17.48	17.48	17.97	17.97	18.12
CO, mg/Nm3 (dry)	19.69	19.69	19.69	19.69	19.69	19.69	19.69
CO, mg/Nm3 (dry, 15% O2)	15.49	15.49	15.30	15.30	15.49	15.49	15.62
CO, mg/Nm3 (dry, 15% O2)	15.49	15.49	15.30	15.30	15.49	15.49	15.62
CO, mg/MJ (LHV)	13.45	13.45	13.28	13.28	13.45	13.45	13.56
CO, mg/MJ (HHV)	12.11	12.11	11.96	11.96	12.11	12.11	12.21
NOTE: SO2 estimate does not include the effects of SO2 oxidation							
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12	0.12
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12	0.12
SO2, ppmvd (with no SO2 oxidation)	0.15	0.15	0.15	0.15	0.15	0.15	0.15
SO2, ppmvw (with no SO2 oxidation)(wet - uncorrected exhaust gas)	0.13	0.13	0.13	0.13	0.14	0.14	0.14
SO2 Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in SO2 Emissions below	5%	5%	5%	5%	5%	5%	5%
SO2, lb/h (with no SO2 oxidation)	1.03	1.03	1.07	1.07	1.14	1.14	1.22
SO2, lb/MBtu (LHV) (with no SO2 oxidation)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
SO2, lb/MBtu (HHV) (with no SO2 oxidation)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
SO2, mg/Nm3 (wet - uncorrected exhaust flow) (with no SO2 oxidation)	0.40	0.40	0.40	0.40	0.41	0.41	0.41
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	0.35	0.35	0.35	0.35	0.35	0.35	0.35
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	0.35	0.35	0.35	0.35	0.35	0.35	0.35
SO2, mg/Nm3 (dry) (with no SO2 oxidation)	0.45	0.45	0.45	0.45	0.45	0.45	0.44
SO2, mg/MJ (LHV) (with no SO2 oxidation)	0.31	0.31	0.31	0.31	0.31	0.31	0.31
SO2, mg/MJ (HHV) (with no SO2 oxidation)	0.27	0.27	0.27	0.27	0.27	0.27	0.27

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,550	173,260	175,940	192,770	18T,860	193,000	192,430
Combustion Turbine Exhaust Emissions - continued							
UHC, ppmvd @ 15% O2	6.17	6.17	6.13	6.13	6.04	6.04	6.04
UHC, ppmvd @ 15% O2	6.17	6.17	6.13	6.13	6.04	6.04	6.04
UHC, ppmvd	7.85	7.85	7.88	7.88	7.67	7.67	7.61
UHC, ppmvw (wet - uncorrected exhaust gas)	7.00	7.00	7.00	7.00	7.00	7.00	7.00
UHC Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in UHC Emissions Below	5%	5%	5%	5%	5%	5%	5%
UHC, lb/h as CH4	13.64	13.64	13.99	13.99	14.73	14.73	15.76
UHC, lb/MBtu as CH4 (LHV)	0.0094	0.0094	0.0093	0.0093	0.0092	0.0092	0.0092
UHC, lb/MBtu as CH4 (HHV)	0.0084	0.0084	0.0084	0.0084	0.0082	0.0082	0.0082
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.64	4.64	4.61	4.61	4.54	4.54	4.54
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.64	4.64	4.61	4.61	4.54	4.54	4.54
UHC, mg/Nm3 as CH4 (dry)	5.90	5.90	5.93	5.93	5.76	5.76	5.72
UHC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	5.26	5.26	5.26	5.26	5.26	5.26	5.26
UHC, mg/MJ as CH4 (LHV)	4.03	4.03	4.00	4.00	3.94	3.94	3.94
UHC, mg/MJ as CH4 (HHV)	3.63	3.63	3.60	3.60	3.55	3.55	3.55
VOC percentage of UHC	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
VOC, ppmvd @ 15% O2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
VOC, ppmvd @ 15% O2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
VOC, ppmvd	1.57	1.57	1.58	1.58	1.53	1.53	1.52
VOC, ppmvw (wet - uncorrected exhaust flow)	1.40	1.40	1.40	1.40	1.40	1.40	1.40
VOC Massflow Added to Match CTG Manufacturer's VOC Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in VOC Emissions below	5%	5%	5%	5%	5%	5%	5%
VOC, lb/h as CH4	2.73	2.73	2.80	2.80	2.95	2.95	3.15
VOC, lb/MBtu as CH4 (LHV)	0.0019	0.0019	0.0019	0.0019	0.0018	0.0018	0.0018
VOC, lb/MBtu as CH4 (HHV)	0.0017	0.0017	0.0017	0.0017	0.0016	0.0016	0.0016
VOC, mg/Nm3 as CH4 (dry, 15% O2)	0.93	0.93	0.92	0.92	0.91	0.91	0.91
VOC, mg/Nm3 as CH4 (dry, 15% O2)	0.93	0.93	0.92	0.92	0.91	0.91	0.91
VOC, mg/Nm3 as CH4 (dry)	1.18	1.18	1.19	1.19	1.15	1.15	1.14
VOC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	1.05	1.05	1.05	1.05	1.05	1.05	1.05
VOC, mg/MJ as CH4 (LHV)	0.81	0.81	0.80	0.80	0.79	0.79	0.79
VOC, mg/MJ as CH4 (HHV)	0.73	0.73	0.72	0.72	0.71	0.71	0.71
Percent Margin Included in Particulates Emissions below	5%	5%	5%	5%	5%	5%	5%
Particulates, lb/h (front half catch only)	9.45	9.45	9.45	9.45	9.45	9.45	9.45
Particulates, lb/h (front and back half catch)	18.90	18.90	18.90	18.90	18.90	18.90	18.90
Particulates, lb/MBtu (LHV) (front half catch only)	0.0065	0.0065	0.0063	0.0063	0.0059	0.0059	0.0055
Particulates, lb/MBtu (HHV) (front half catch only)	0.0058	0.0058	0.0057	0.0057	0.0053	0.0053	0.0049
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	3.22	3.22	3.11	3.11	2.91	2.91	2.72
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	3.22	3.22	3.11	3.11	2.91	2.91	2.72
Particulates, mg/Nm3 (dry) (front half catch only)	4.09	4.09	4.00	4.00	3.70	3.70	3.43
Particulates, mg/Nm3 (wet - uncorrected exhaust flow) (front half catch only)	3.65	3.65	3.56	3.56	3.38	3.38	3.16
Particulates, mg/MJ (LHV) (front half catch only)	2.79	2.79	2.70	2.70	2.53	2.53	2.36
Particulates, mg/MJ (HHV) (front half catch only)	2.51	2.51	2.43	2.43	2.28	2.28	2.13
Percent Margin Included in PM10 Emissions below	5%	5%	5%	5%	5%	5%	5%
PM10, lb/h (front half catch only)	9.45	9.45	9.45	9.45	9.45	9.45	9.45
PM10, lb/h (front and back half catch)	18.90	18.90	18.90	18.90	18.90	18.90	18.90
PM10, lb/MBtu (LHV) (front and back half catch)	0.01	0.01	0.01	0.01	0.01	0.01	0.01
PM10, lb/MBtu (HHV) (front and back half catch)	0.01	0.01	0.01	0.01	0.01	0.01	0.01
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	6.43	6.43	6.23	6.23	5.82	5.82	5.44
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	6.43	6.43	6.23	6.23	5.82	5.82	5.44
PM10, mg/Nm3 (dry) (front and back half catch)	8.17	8.17	8.01	8.01	7.40	7.40	6.86
PM10, mg/Nm3 (wet - uncorrected exhaust flow) (front and back half catch)	7.29	7.29	7.11	7.11	6.75	6.75	6.31
PM10, mg/MJ (LHV) (front and back half catch)	5.58	5.58	5.40	5.40	5.05	5.05	4.72
PM10, mg/MJ (HHV) (front and back half catch)	5.03	5.03	4.87	4.87	4.55	4.55	4.25
CTG Wet (Total) Exhaust Gas Analysis							
Molecular Wt, lb/mol	28.13	28.13	28.09	28.09	28.36	28.36	28.45
Molecular Wt, kg/mol	12.76	12.76	12.74	12.74	12.86	12.86	12.90
Gas Constant, ft-lbf/lbm-R	54.927	54.927	55.011	55.011	54.474	54.474	54.314
Specific Volume, ft^3/lb	40.33	40.33	40.20	40.20	39.31	39.31	38.32
Specific Volume, m^3/kg	2.52	2.52	2.51	2.51	2.45	2.45	2.39
Exhaust Gas Flow, acfm	2,187,230	2,187,230	2,231,978	2,231,978	2,320,600	2,320,600	2,427,572
Specific Volume, scf/lb	13.49	13.49	13.51	13.51	13.38	13.38	13.34
Exhaust Gas Flow, scfm	731,608	731,608	750,100	750,100	789,866	789,866	845,089
Specific Volume, Nm3/kg	0.7967	0.7967	0.7979	0.7979	0.7901	0.7901	0.7878
Exhaust Gas Flow, Nm3/s	326.64	326.64	334.91	334.91	352.61	352.61	377.29

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,550	173,260	175,940	192,770	187,860	193,000	192,430
Duct Burner Emissions							
Duct Burner Heat Input, MBtu/h (LHV) (margin included)	76.7	0.0	0.0	66.9	0.0	20.6	0.0
Duct Burner Heat Input, GJ/h (LHV) (margin included)	80.9	0.0	0.0	70.6	0.0	21.7	0.0
Duct Burner Heat Input, MBtu/h (HHV) (margin included)	85.2	0.0	0.0	74.3	0.0	22.9	0.0
Duct Burner Heat Input, GJ/h (HHV) (margin included)	89.9	0.0	0.0	78.4	0.0	24.1	0.0
Total Duct Burner Fuel Flow, lb/h	3,710	0	0	3,236	0	996	0
Duct Burner Fuel LHV, Btu/lb	20,675	20,675	20,675	20,675	20,675	20,675	20,675
Duct Burner Fuel HHV, kJ/kg	48,090	48,090	48,090	48,090	48,090	48,090	48,090
Duct Burner Fuel HHV, Btu/lb	22,962	22,962	22,962	22,962	22,962	22,962	22,962
Duct Burner Fuel HHV, kJ/kg	53,410	53,410	53,410	53,410	53,410	53,410	53,410
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%
H2	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%
N2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner NOx, kg/kJ (HHV)	0.034	0.034	0.034	0.034	0.034	0.034	0.034
Duct Burner CO, lb/MBtu (HHV)	0.100	0.100	0.100	0.100	0.100	0.100	0.100
Duct Burner CO, kg/kJ (HHV)	0.043	0.043	0.043	0.043	0.043	0.043	0.043
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner UHC, kg/kJ (HHV)	0.026	0.026	0.026	0.026	0.026	0.026	0.026
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Duct Burner VOC (as CH4), kg/kJ (HHV)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, kg/kJ (HHV) (front half catch only)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner Particulate, lb/MBtu (HHV) (front and back half catch)	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Duct Burner Particulate, kg/kJ (HHV) (front and back half catch)	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Duct Burner PM10, kg/kJ (HHV) (front half catch only)	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Duct Burner PM10, kg/kJ (HHV) (front and back half catch)	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Total SO2, lb/h from Duct Burner	0.052	0.000	0.000	0.045	0.000	0.014	0.000
Total SO2, kg/h from Duct Burner	0.024	0.000	0.000	0.021	0.000	0.006	0.000
DB NOx, lb/h	6.81	0.00	0.00	5.94	0.00	1.83	0.00
DB NOx, kg/h	3.09	0.00	0.00	2.70	0.00	0.83	0.00
DB CO, lb/h	8.52	0.00	0.00	7.43	0.00	2.29	0.00
DB CO, kg/h	3.86	0.00	0.00	3.37	0.00	1.04	0.00
DB UHC (as CH4), lb/h	5.11	0.00	0.00	4.46	0.00	1.37	0.00
DB UHC (as CH4), kg/h	2.32	0.00	0.00	2.02	0.00	0.62	0.00
DB VOC (as CH4), lb/h	2.04	0.00	0.00	1.78	0.00	0.55	0.00
DB VOC (as CH4), kg/h	0.93	0.00	0.00	0.81	0.00	0.25	0.00
DB Particulate, lb/h (front half catch only)	0.85	0.00	0.00	0.74	0.00	0.23	0.00
DB Particulate, kg/h (front half catch only)	0.39	0.00	0.00	0.34	0.00	0.10	0.00
DB Particulate, lb/h (front and back half catch)	1.70	0.00	0.00	1.49	0.00	0.46	0.00
DB Particulate, kg/h (front and back half catch)	0.77	0.00	0.00	0.67	0.00	0.21	0.00
DB PM10, lb/h (front half catch only)	0.68	0.00	0.00	0.59	0.00	0.18	0.00
DB PM10, kg/h (front half catch only)	0.31	0.00	0.00	0.27	0.00	0.08	0.00
DB PM10, lb/h (front and back half catch)	1.36	0.00	0.00	1.19	0.00	0.37	0.00
DB PM10, kg/h (front and back half catch)	0.62	0.00	0.00	0.54	0.00	0.17	0.00

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,550	173,260	175,940	192,770	187,860	193,000	192,430
Heat Recovery Steam Generator Stack Emissions							
NOTE: Exhaust Analysis does not include the effects of post combustion control							
Stack Exhaust Analysis (Volume Basis - Wet)							
Ar	0.91%	0.91%	0.91%	0.91%	0.93%	0.93%	0.94%
CO2	3.99%	3.79%	3.82%	3.99%	3.88%	3.93%	3.88%
H2O	11.16%	10.79%	11.20%	11.52%	8.72%	8.82%	7.96%
N2	72.43%	72.57%	72.27%	72.15%	74.25%	74.21%	74.85%
O2	11.51%	11.93%	11.80%	11.44%	12.21%	12.11%	12.37%
SO2	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%
Stack Emissions							
NOx, ppmvd @15% O2 w/o SCR	9.62	9.00	9.00	9.53	9.00	9.16	9.00
NOx, ppmvd@ user defined oxygen w/o SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w/o SCR	12.90	11.44	11.58	12.83	11.44	11.79	11.34
NOx, ppmvw w/o SCR	11.46	10.20	10.28	11.35	10.44	10.75	10.44
NOx, lb/h as NO2 w/o SCR	60.84	54.03	55.91	61.85	59.97	61.80	64.38
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w/o SCR	0.04	0.04	0.04	0.04	0.04	0.04	0.04
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w/o SCR	0.04	0.03	0.03	0.04	0.03	0.03	0.03
NOx, kg/h as NO2	27.60	24.51	25.36	28.05	27.20	28.03	29.20
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w/o SCR	23.42	20.84	21.03	23.23	21.43	22.07	21.50
NOx, mg/MJ (LHV) (including duct burner fuel) w/o SCR	17.07	15.96	15.98	16.93	16.04	16.32	16.09
NOx, mg/MJ (HHV) (including duct burner fuel) w/o SCR	15.37	14.37	14.39	15.24	14.44	14.69	14.49
NOx, ppmvd @15% O2 w/ SCR	3.50	3.50	3.50	3.50	3.50	3.50	3.50
NOx, ppmvd@ user defined oxygen w/ SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w SCR	4.69	4.45	4.50	4.71	4.45	4.51	4.41
NOx, ppmvw w SCR	4.17	3.97	4.00	4.17	4.06	4.11	4.06
NOx, lb/h as NO2 w/ SCR	22.23	21.12	21.82	22.79	23.32	23.62	24.95
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w SCR	0.01	0.01	0.01	0.01	0.01	0.01	0.01
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w SCR	0.01	0.01	0.01	0.01	0.01	0.01	0.01
NOx, kg/h as NO2	10.09	9.58	9.90	10.34	10.58	10.71	11.32
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w SCR	8.56	8.15	8.21	8.56	8.33	8.44	8.33
NOx, mg/MJ (LHV) (including duct burner fuel) w SCR	6.24	6.24	6.24	6.24	6.24	6.24	6.24
NOx, mg/MJ (HHV) (including duct burner fuel) w SCR	5.62	5.62	5.62	5.62	5.62	5.62	5.62
SCR NH3 slip, ppmvd @15% O2	10.00	10.00	10.00	10.00	10.00	10.00	10.00
SCR NH3 slip, lb/h	23.52	22.34	23.08	24.10	24.67	24.98	26.39
CO, ppmvd @ 15% O2 w/o Catalyst	13.41	11.80	11.66	13.04	11.81	12.21	11.90
CO, ppmvd @ user defined O2 w/o Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/o Catalyst	17.99	15.00	15.00	17.55	15.00	15.73	15.00
CO, ppmvw w/o Catalyst	15.98	13.38	13.32	15.53	13.69	14.34	13.81
CO, lb/h w/o Catalyst	54.05	45.53	46.47	53.90	50.29	52.58	54.26
CO, lb/MBtu (LHV) (incl. duct burner fuel) w/o SCR	0.04	0.03	0.03	0.03	0.03	0.03	0.03
CO, lb/MBtu (HHV) (incl. duct burner fuel) w/o SCR	0.03	0.03	0.03	0.03	0.03	0.03	0.03
CO Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd @ 15% O2 w/ Catalyst	13.41	11.80	11.66	13.04	11.81	12.21	11.90
CO, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/ Catalyst	17.99	15.00	15.00	17.55	15.00	15.73	15.00
CO, ppmvw w/ Catalyst	15.98	13.38	13.32	15.53	13.69	14.34	13.81
CO, lb/h w/ Catalyst	51.88	43.36	44.25	51.68	47.89	50.18	51.67
CO, lb/MBtu (LHV) (incl. duct burner fuel) w SCR	0.034	0.030	0.029	0.033	0.030	0.031	0.030
CO, lb/MBtu (HHV) (incl. duct burner fuel) w SCR	0.030	0.027	0.026	0.030	0.027	0.028	0.027
SO2, ppmvd@15% O2 (with no SO2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12	0.12
SO2, ppmvd at user defined O2 (with no SO2 oxidation)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
SO2, ppmvd (with no SO2 oxidation)	0.16	0.15	0.15	0.16	0.15	0.15	0.15
SO2, ppmvw (with no SO2 oxidation)	0.14	0.13	0.13	0.14	0.14	0.14	0.14
SO2, lb/h (with no SO2 oxidation)	1.09	1.03	1.07	1.11	1.14	1.16	1.22
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	1	2	3	4	5	6	7
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	100%	100%	100%
Ambient Temperature, F	95	95	95	95	59	59	20
HRSG Firing	Fired	Unfired	Unfired	Fired	Unfired	Fired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	192,550	173,260	175,940	192,770	187,860	193,000	192,430
Heat Recovery Steam Generator Stack Emissions - continued							
NOTE: UHC calculations do NOT include the effect of any oxidation in the CO catalyst.							
UHC, ppmvd @ 15% O_2	8.17	6.17	6.13	7.83	6.04	6.54	6.04
UHC, ppmvd @ user defined O_2	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
UHC, ppmvd	10.96	7.85	7.88	10.54	7.67	8.42	7.61
UHC, ppmvw	9.73	7.00	7.00	9.33	7.00	7.68	7.00
UHC, lb/h as CH_4	18.75	13.64	13.99	18.44	14.73	16.10	15.76
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.012	0.009	0.009	0.012	0.009	0.010	0.009
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.011	0.008	0.008	0.011	0.008	0.009	0.008
VOC, ppmvd @ 15% O_2 w/o Catalyst	2.10	1.23	1.23	1.96	1.21	1.43	1.21
VOC, ppmvd @ user defined O_2 w/o CO catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/o Catalyst	2.81	1.57	1.58	2.64	1.53	1.84	1.52
VOC, ppmvw w/o Catalyst	2.50	1.40	1.40	2.33	1.40	1.67	1.40
VOC, lb/h as CH_4 w/o Catalyst	4.77	2.73	2.80	4.58	2.95	3.49	3.15
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w/o CO catalyst	0.0031	0.0019	0.0019	0.0029	0.0018	0.0021	0.0018
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w/o CO catalyst	0.0028	0.0017	0.0017	0.0026	0.0016	0.0019	0.0016
VOC Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%	0%
VOC, ppmvd @ 15% O_2 w/ Catalyst	2.10	1.23	1.23	1.96	1.21	1.43	1.21
VOC, ppmvd @ user defined O_2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/ Catalyst	2.81	1.57	1.58	2.64	1.53	1.84	1.52
VOC, ppmvw w/ Catalyst	2.50	1.40	1.40	2.33	1.40	1.67	1.40
VOC, lb/h as CH_4 w/ Catalyst	4.64	2.60	2.66	4.45	2.80	3.35	3.00
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w CO catalyst	0.0030	0.0018	0.0018	0.0028	0.0017	0.0021	0.0017
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w CO catalyst	0.0027	0.0016	0.0016	0.0025	0.0016	0.0019	0.0016
Particulate without the effect of SO_2 oxidation and SCR catalysts							
Particulates, lb/h (front half catch only)	10.3	9.5	9.5	10.2	9.5	9.7	9.5
Particulates, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.0067	0.0065	0.0063	0.0065	0.0059	0.0059	0.0055
Particulates, lb/h (front and back half catch)	20.6	18.9	18.9	20.4	18.9	19.4	18.9
Particulates, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.013	0.013	0.013	0.013	0.012	0.012	0.011
PM10, lb/h (front half catch only)	10.1	9.5	9.5	10.0	9.5	9.6	9.5
PM10, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.007	0.006	0.006	0.006	0.006	0.006	0.005
PM10, lb/h (front and back half catch)	20.3	18.9	18.9	20.1	18.9	19.3	18.9
PM10, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.013	0.013	0.013	0.013	0.012	0.012	0.011
Particulate including the effect of SO_2 oxidation and SCR catalysts [includes $2(NH_4SO_4)$]							
Particulates, lb/h (front half catch only)	10.7	9.8	9.8	10.6	9.9	10.1	9.9
Particulates, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.0070	0.0067	0.0065	0.0067	0.0061	0.0062	0.0057
Particulates, lb/h (front and back half catch)	21.0	19.3	19.3	20.8	19.3	19.8	19.3
Particulates, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.014	0.013	0.013	0.013	0.012	0.012	0.011
PM10, lb/h (front half catch only)	10.5	9.8	9.8	10.4	9.9	10.0	9.9
PM10, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.007	0.007	0.007	0.007	0.006	0.006	0.006
PM10, lb/h (front and back half catch)	20.6	19.3	19.3	20.5	19.3	19.7	19.3
PM10, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.013	0.013	0.013	0.013	0.012	0.012	0.011
NOTE: SO_2 to SO_3 conversion rate (assumed), wt%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
SO_3 conversion rate (assumed) to ammonium sulfates [$2(NH_4SO_4)$]	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Remaining SO_2 in Exhaust Gas, lb/h	0.98	0.93	0.96	1.00	1.03	1.04	1.10
Amount of SO_2 converted to SO_3	0.11	0.10	0.11	0.11	0.11	0.12	0.12
Maximum Exhaust Gas ammonium sulfate [$2(NH_4SO_4)$], lb/h	0.39	0.37	0.38	0.40	0.41	0.41	0.44
Maximum H_2SO_4 (assuming 100% conversion from SO_3 to H_2SO_4), lb/hr	0.17	0.16	0.16	0.17	0.17	0.18	0.19
Stack Exit Temperature, F	205	208	209	207	206	204	208
Stack Diameter, ft (estimated)	19	19	19	19	19	19	19
Stack Flow, lb/h	3,257,710	3,254,000	3,331,310	3,334,546	3,542,000	3,542,996	3,801,000
Stack Flow, scfm	732,985	731,608	750,100	751,384	789,866	790,068	845,089
Stack Flow, acfm	938,220	939,864	966,080	964,239	1,011,241	1,009,754	1,085,819
Stack Exit Velocity, ft/s	55.2	55.2	56.8	56.7	59.4	59.4	63.8
Selective Catalytic Reduction (SCR)							
NO_x Removed, lb/h as NO_2	38.6	32.9	34.1	39.1	36.6	38.2	39.4
NO_x Removed, percent	63.5%	60.9%	61.0%	63.2%	61.1%	61.8%	61.2%
NH_3 Slip, lb/h	23.5	22.3	23.1	24.1	24.7	25.0	26.4
Total NH_3 consumption, lb/h (1:1 stoichiometric ratio, incl. slip)	37.8	34.5	35.7	38.6	38.2	39.1	41.0
Adjusted Stack Diameter (ft) estimated	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	61.4	61.5	63.3	63.1	66.2	66.1	71.1

Notes:

1. The emissions estimates shown in the table above are per stack.

2. The combustion turbine generator performance and emissions is based on a General Electric performance estimate provided by JEA

3 The combustion turbine emissions estimate may include margin as indicated in the table.

Where catalysts are involved to reduce emissions, the margin applied to the CTG emissions only affects the amount of emissions removed, but not the stack emissions

4 UHC calculations do not include the effects of any oxidation in the CO catalyst. It was assumed that the VOC/UHC ratio is 20% for natural gas firing, and 50% for distillate oil firing.

5. It was assumed that the front and back half catch of CTG particulate emissions is twice the amount of front half catch only

6 Duct Burner emissions are Black & Veatch estimates based on typical vendor data.

7. It was assumed that ammonium sulfate is measured as front half particulates. The assumption that 100% SO_3 is converted to ammonium sulfates results in "worst case" particulate emissions.

8 The maximum amount of ammonium sulfates and sulfuric acid shown in the table can not occur in parallel at the same time.

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,780	161,900	142,180
Ambient Temperature, F	95.0	95.0	59.0	59.0	20.0	20.0
Ambient Temperature, C	35.0	35.0	15.0	15.0	(6.7)	(6.7)
Ambient Relative Humidity, %	60.0	60.0	60.0	60.0	60.0	60.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690
Atmospheric Pressure, bar(a)	1.013	1.013	1.013	1.013	1.013	1.013
CTG Compressor Inlet Dry Bulb Temperature, F	95.0	95.0	59.0	59.0	20.0	20.0
CTG Compressor Inlet Temperature, C	35.0	35.0	15.0	15.0	(6.7)	(6.7)
CTG Compr. Inlet Relative Humidity, %	60.1	60.1	60.2	60.2	60.3	60.3
CTG Inlet Air Conditioning Included?	No	No	No	No	No	No
Inlet Loss, in. H2O	3.5	3.5	3.5	3.5	3.5	3.5
Inlet Loss, mm. H2O	88.9	88.9	88.9	88.9	88.9	88.9
Exhaust Loss, in. H2O	15.0	15.0	15.0	15.0	15.0	15.0
Exhaust Loss, mm. H2O	381.0	381.0	381.0	381.0	381.0	381.0
CTG Load Level (percent of Base Load)	75%	50%	75%	50%	75%	50%
Gross CTG Output, kW	111,300	74,200	128,170	85,450	138,040	92,060
Gross CTG Heat Rate, Btu/kWh (LHV)	10,734	12,994	10,159	12,241	9,991	11,963
Gross CTG Heat Rate, KJ/KWh (LHV)	11,325	13,709	10,719	12,915	10,541	12,622
Gross CTG Heat Rate, kJ/kWh (HHV)	11,921	14,431	11,283	13,595	11,096	13,287
Gross CTG Heat Rate, KJ/KWh (HHV)	12,577	15,226	11,904	14,343	11,707	14,019
CTG Heat Input, MBtu/h (LHV)	1,194.7	964.2	1,302.1	1,046.0	1,379.1	1,101.3
CTG Heat Input, GJ/h (LHV)	1,260.5	1,017.2	1,373.8	1,103.6	1,455.1	1,162.0
CTG Heat Input, MBtu/h (HHV)	1,326.9	1,070.8	1,446.2	1,161.7	1,531.7	1,223.2
CTG Heat Input, GJ/h (HHV)	1,399.9	1,129.8	1,525.8	1,225.6	1,616.0	1,290.5
CTG Water Injection Flow, lb/h	0	0	0	0	0	0
CTG Water Injection Flow, kg/h	0	0	0	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0
CTG Steam Injection Flow, kg/h	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	2,691,000	2,265,000	2,890,000	2,397,000	3,025,000	2,486,000
CTG Exhaust Flow, kg/h	1,220,617	1,027,387	1,310,882	1,087,261	1,372,117	1,127,631
CTG Exhaust Temperature, F	1,177	1,207	1,146	1,191	1,119	1,167
CTG Exhaust Temperature, C	636.1	652.8	618.9	643.9	603.9	630.6
CTG Exhaust Enthalpy, Btu/lb	291.52	299.63	288.32	300.69	289.38	302.54
CTG Exhaust Enthalpy, kJ/lb	307.57	316.13	304.19	317.24	305.31	319.20
CTG Exhaust Enthalpy Reference Temperature, F	95	95	59	59	20	20
CTG Exhaust Enthalpy Reference Temperature, C	35.0	35.0	15.0	15.0	(6.7)	(6.7)
CTG Exhaust Heat, MBtu/h	784.5	678.7	833.2	720.8	875.4	752.1
CTG Exhaust Heat, GJ/h	827.7	716.0	879.1	760.4	923.6	793.5
CTG Exhaust Heat/CTG Output, kW/kW	206.6%	268.0%	190.5%	247.2%	185.8%	239.4%
Total CTG Fuel Flow, lb/h	57790	46630	62980	50590	66710	53270
CTG Fuel Temperature, F	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,675	20,675	20,675	20,675	20,675	20,675
CTG Fuel LHV, kJ/lb	48,090	48,090	48,090	48,090	48,090	48,090
CTG Fuel HHV, Btu/lb	22,962	22,962	22,962	22,962	22,962	22,962
CTG Fuel HHV, kJ/lb	53,410	53,410	53,410	53,410	53,410	53,410
HHV/LHV Ratio	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%
H2	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%
N2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.2	0.2	0.2	0.2	0.2	0.2

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,760	161,900	142,180
Combustion Turbine Exhaust Emissions						
CTG Exhaust Analysis (Volume Basis - Wet)						
Ar	0.91%	0.91%	0.93%	0.93%	0.94%	0.94%
CO_2	3.77%	3.61%	3.85%	3.73%	3.91%	3.80%
H_2O	10.73%	10.43%	8.67%	8.43%	8.02%	7.80%
N_2	72.59%	72.71%	74.27%	74.36%	74.82%	74.91%
O_2	12.00%	12.33%	12.27%	12.54%	12.31%	12.55%
SO_2	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%
NOx, ppmvd @15% O_2	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd @ 15% O_2	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd	11.35	10.85	11.35	10.97	11.43	11.09
NOx, ppmvw (wet - uncorrected exhaust gas)	10.13	9.72	10.36	10.04	10.52	10.22
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
Additonal Percent Margin included in NOx Emissions below	5%	5%	5%	5%	5%	5%
NOx, lb/h as NO_2	43.81	34.77	48.01	37.97	51.03	40.14
NOx, lb/MBtu (LHV)	0.04	0.04	0.04	0.04	0.04	0.04
NOx, lb/MBtu (HHV)	0.03	0.03	0.03	0.03	0.03	0.03
NOx, mg/Nm3 as NO_2 (dry, 15% O_2)	18.16	17.86	18.26	17.98	18.32	18.05
NOx, mg/Nm3 as NO_2 (dry, 15% O_2)	18.16	17.86	18.26	17.98	18.32	18.05
NOx, mg/Nm3 as NO_2 (dry)	22.89	21.53	23.02	21.91	23.28	22.24
NOx, mg/Nm3 as NO_2 (wet - uncorrected exhaust flow)	20.43	19.28	21.03	20.06	21.41	20.51
NOx, mg/MJ (LHV)	15.76	15.50	15.85	15.61	15.91	15.67
NOx, mg/MJ (HHV)	14.19	13.96	14.27	14.05	14.32	14.11
CO, ppmvd @ 15% O_2	11.90	12.44	11.90	12.31	11.81	12.18
CO, ppmvd @ 15% O_2	11.90	12.44	11.90	12.31	11.81	12.18
CO, ppmvd	15.00	15.00	15.00	15.00	15.00	15.00
CO, ppmvw (wet - uncorrected exhaust gas)	13.39	13.44	13.70	13.74	13.80	13.83
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin included in CO Emissions below	5%	5%	5%	5%	5%	5%
CO, lb/h	37.67	31.79	41.05	34.12	43.16	35.53
CO, lb/MBtu (LHV)	0.03	0.03	0.03	0.03	0.03	0.03
CO, lb/MBtu (HHV)	0.03	0.03	0.03	0.03	0.03	0.03
CO, mg/Nm3 (wet - uncorrected exhaust flow)	17.57	17.63	17.98	18.03	18.11	18.15
CO, mg/Nm3 (dry)	19.69	19.69	19.69	19.69	19.69	19.69
CO, mg/Nm3 (dry, 15% O_2)	15.62	16.33	15.61	16.16	15.50	15.98
CO, mg/Nm3 (dry, 15% O_2)	15.62	16.33	15.61	16.16	15.50	15.98
CO, mg/MJ (LHV)	13.56	14.18	13.55	14.02	13.45	13.87
CO, mg/MJ (HHV)	12.21	12.76	12.20	12.63	12.11	12.49
NOTE: SO_2 estimate does not include the effects of SO_2 oxidation						
SO_2, ppmvd @ 15% O_2 (with no SO_2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12
SO_2, ppmvd @ 15% O_2 (with no SO_2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12
SO_2, ppmvd (with no SO_2 oxidation)	0.15	0.14	0.15	0.14	0.15	0.14
SO_2, ppmvw (with no SO_2 oxidation)(wet - uncorrected exhaust gas)	0.13	0.13	0.13	0.13	0.14	0.13
SO_2 Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin included in SO_2 Emissions below	5%	5%	5%	5%	5%	5%
SO_2, lb/h (with no SO_2 oxidation)	0.85	0.88	0.92	0.74	0.98	0.78
SO_2, lb/MBtu (LHV) (with no SO_2 oxidation)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
SO_2, lb/MBtu (HHV) (with no SO_2 oxidation)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
SO_2, mg/Nm3 (wet - uncorrected exhaust flow) (with no SO_2 oxidation)	0.40	0.38	0.41	0.39	0.41	0.40
SO_2, mg/Nm3 (dry, 15% O_2) (with no SO_2 oxidation)	0.35	0.35	0.35	0.35	0.35	0.35
SO_2, mg/Nm3 (dry, 15% O_2) (with no SO_2 oxidation)	0.35	0.35	0.35	0.35	0.35	0.35
SO_2, mg/Nm3 (dry) (with no SO_2 oxidation)	0.44	0.42	0.44	0.43	0.45	0.43
SO_2, mg/MJ (LHV) (with no SO_2 oxidation)	0.31	0.31	0.31	0.31	0.31	0.31
SO_2, mg/MJ (HHV) (with no SO_2 oxidation)	0.27	0.27	0.27	0.27	0.27	0.27

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,760	161,900	142,180
Combustion Turbine Exhaust Emissions - continued						
UHC, ppmvd @ 15% O2	6.22	6.48	6.08	6.27	5.99	6.16
UHC, ppmvd @ 15% O2	6.22	6.48	6.08	6.27	5.99	6.16
UHC, ppmvd	7.84	7.82	7.66	7.64	7.61	7.59
UHC, ppmvw (wet - uncorrected exhaust gas)	7.00	7.00	7.00	7.00	7.00	7.00
UHC Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in UHC Emissions Below	5%	5%	5%	5%	5%	5%
UHC, lb/h as CH4	11.28	9.49	12.01	9.96	12.54	10.30
UHC, lb/MBtu as CH4 (LHV)	0.0094	0.0098	0.0092	0.0095	0.0091	0.0094
UHC, lb/MBtu as CH4 (HHV)	0.0085	0.0089	0.0083	0.0086	0.0082	0.0084
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.68	4.87	4.57	4.72	4.50	4.63
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.68	4.87	4.57	4.72	4.50	4.63
UHC, mg/Nm3 as CH4 (dry)	5.89	5.87	5.76	5.75	5.72	5.71
UHC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	5.26	5.26	5.26	5.26	5.26	5.26
UHC, mg/MJ as CH4 (LHV)	4.06	4.23	3.97	4.09	3.91	4.02
UHC, mg/MJ as CH4 (HHV)	3.65	3.81	3.57	3.69	3.52	3.62
VOC percentage of UHC	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
VOC, ppmvd @ 15% O2	1.2	1.3	1.2	1.3	1.2	1.2
VOC, ppmvd @ 15% O2	1.2	1.3	1.2	1.3	1.2	1.2
VOC, ppmvd	1.57	1.56	1.53	1.53	1.52	1.52
VOC, ppmvw (wet - uncorrected exhaust flow)	1.40	1.40	1.40	1.40	1.40	1.40
VOC Massflow Added to Match CTG Manufacturer's VOC Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in VOC Emissions below	5%	5%	5%	5%	5%	5%
VOC, lb/h as CH4	2.26	1.90	2.40	1.99	2.51	2.06
VOC, lb/MBtu as CH4 (LHV)	0.0019	0.0020	0.0018	0.0019	0.0018	0.0019
VOC, lb/MBtu as CH4 (HHV)	0.0017	0.0018	0.0017	0.0017	0.0016	0.0017
VOC, mg/Nm3 as CH4 (dry, 15% O2)	0.94	0.97	0.91	0.94	0.90	0.93
VOC, mg/Nm3 as CH4 (dry, 15% O2)	0.94	0.97	0.91	0.94	0.90	0.93
VOC, mg/Nm3 as CH4 (dry)	1.18	1.17	1.15	1.15	1.14	1.14
VOC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	1.05	1.05	1.05	1.05	1.05	1.05
VOC, mg/MJ as CH4 (LHV)	0.81	0.85	0.79	0.82	0.78	0.80
VOC, mg/MJ as CH4 (HHV)	0.73	0.76	0.71	0.74	0.70	0.72
Percent Margin Included in Particulates Emissions below	5%	5%	5%	5%	5%	5%
Particulates, lb/h (front half catch only)	9.45	9.45	9.45	9.45	9.45	9.45
Particulates, lb/h (front and back half catch)	18.90	18.90	18.90	18.90	18.90	18.90
Particulates, lb/MBtu (LHV) (front half catch only)	0.0079	0.0098	0.0073	0.0090	0.0069	0.0086
Particulates, lb/MBtu (HHV) (front half catch only)	0.0071	0.0088	0.0065	0.0081	0.0062	0.0077
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	3.92	4.85	3.59	4.47	3.39	4.25
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	3.92	4.85	3.59	4.47	3.39	4.25
Particulates, mg/Nm3 (dry) (front half catch only)	4.94	5.85	4.53	5.45	4.31	5.24
Particulates, mg/Nm3 (wet - uncorrected exhaust flow) (front half catch only)	4.41	5.24	4.14	4.99	3.96	4.83
Particulates, mg/MJ (LHV) (front half catch only)	3.40	4.21	3.12	3.88	2.95	3.69
Particulates, mg/MJ (HHV) (front half catch only)	3.06	3.79	2.81	3.50	2.66	3.32
Percent Margin Included in PM10 Emissions below	5%	5%	5%	5%	5%	5%
PM10, lb/h (front half catch only)	9.45	9.45	9.45	9.45	9.45	9.45
PM10, lb/h (front and back half catch)	18.90	18.90	18.90	18.90	18.90	18.90
PM10, lb/MBtu (LHV) (front and back half catch)	0.02	0.02	0.01	0.02	0.01	0.02
PM10, lb/MBtu (HHV) (front and back half catch)	0.01	0.02	0.01	0.02	0.01	0.02
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	7.83	9.71	7.19	8.95	6.79	8.50
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	7.83	9.71	7.19	8.95	6.79	8.50
PM10, mg/Nm3 (dry) (front and back half catch)	9.88	11.70	9.06	10.91	8.62	10.47
PM10, mg/Nm3 (wet - uncorrected exhaust flow) (front and back half catch)	8.82	10.48	8.28	9.99	7.93	9.65
PM10, mg/MJ (LHV) (front and back half catch)	6.80	8.43	6.24	7.77	5.89	7.38
PM10, mg/MJ (HHV) (front and back half catch)	6.12	7.59	5.62	6.99	5.30	6.64
CTG Wet (Total) Exhaust Gas Analysis						
Molecular Wt, lb/mol	28.13	28.15	28.37	28.38	28.44	28.46
Molecular Wt, kg/mol	12.76	12.77	12.87	12.87	12.90	12.91
Gas Constant, ft-lbf/lbm-R	54.920	54.882	54.467	54.438	54.321	54.294
Specific Volume, ft^3/lb	40.98	41.70	39.87	40.97	39.10	40.27
Specific Volume, m^3/kg	2.56	2.60	2.49	2.56	2.44	2.51
Exhaust Gas Flow, acfm	1,837,953	1,574,175	1,920,405	1,636,752	1,971,292	1,668,520
Specific Volume, scf/lb	13.49	13.48	13.38	13.37	13.34	13.33
Exhaust Gas Flow, scfm	605,027	506,870	644,470	534,132	672,558	552,306
Specific Volume, Nm3/kg	0.7966	0.7960	0.7900	0.7896	0.7879	0.7875
Exhaust Gas Flow, Nm3/s	270.10	227.17	287.67	238.47	300.30	246.67

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,760	161,900	142,180
Duct Burner Emissions						
Duct Burner Heat Input, MBtu/h (LHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (LHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (HHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,675	20,675	20,675	20,675	20,675	20,675
Duct Burner Fuel HHV, kJ/kg	48,090	48,090	48,090	48,090	48,090	48,090
Duct Burner Fuel HHV, Btu/lb	22,962	22,962	22,962	22,962	22,962	22,962
Duct Burner Fuel HHV, kJ/kg	53,410	53,410	53,410	53,410	53,410	53,410
Duct Burner Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	74.87%	74.87%	74.87%	74.87%	74.87%	74.87%
H2	25.13%	25.13%	25.13%	25.13%	25.13%	25.13%
N2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%	0.00070%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.2	0.2	0.2	0.2	0.2	0.2
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner NOx, kg/kJ (HHV)	0.034	0.034	0.034	0.034	0.034	0.034
Duct Burner CO, lb/MBtu (HHV)	0.100	0.100	0.100	0.100	0.100	0.100
Duct Burner CO, kg/kJ (HHV)	0.043	0.043	0.043	0.043	0.043	0.043
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner UHC, kg/kJ (HHV)	0.026	0.026	0.026	0.026	0.026	0.026
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.024	0.024	0.024	0.024	0.024	0.024
Duct Burner VOC (as CH4), kg/kJ (HHV)	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, kg/kJ (HHV) (front half catch only)	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner Particulate, lb/MBtu (HHV) (front and back half catch)	0.020	0.020	0.020	0.020	0.020	0.020
Duct Burner Particulate, kg/kJ (HHV) (front and back half catch)	0.009	0.009	0.009	0.009	0.009	0.009
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.008	0.008	0.008	0.008	0.008	0.008
Duct Burner PM10, kg/kJ (HHV) (front half catch only)	0.003	0.003	0.003	0.003	0.003	0.003
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.016	0.016	0.016	0.016	0.016	0.016
Duct Burner PM10, kg/kJ (HHV) (front and back half catch)	0.007	0.007	0.007	0.007	0.007	0.007
Total SO2, lb/h from Duct Burner	0.000	0.000	0.000	0.000	0.000	0.000
Total SO2, kg/h from Duct Burner	0.000	0.000	0.000	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00	0.00	0.00	0.00
DB NOx, kg/h	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, kg/h	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), kg/h	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), kg/h	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, kg/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, kg/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, kg/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, kg/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,760	161,900	142,180
Heat Recovery Steam Generator Stack Emissions						
NOTE: Exhaust Analysis does not include the effects of post combustion control						
Stack Exhaust Analysis (Volume Basis - Wet)						
Ar	0.91%	0.91%	0.93%	0.93%	0.94%	0.94%
CO2	3.77%	3.61%	3.85%	3.73%	3.91%	3.80%
H2O	10.73%	10.43%	8.67%	8.43%	8.02%	7.80%
N2	72.59%	72.71%	74.27%	74.36%	74.82%	74.91%
O2	12.00%	12.33%	12.27%	12.54%	12.31%	12.55%
SO2	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%
Stack Emissions						
NOx, ppmvd @15% O2 w/o SCR	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd@ user defined oxygen w/o SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w/o SCR	11.35	10.85	11.35	10.97	11.43	11.09
NOx, ppmvw w/o SCR	10.13	9.72	10.36	10.04	10.52	10.22
NOx, lb/h as NO2 w/o SCR	43.81	34.77	48.01	37.97	51.03	40.14
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w/o SCR	0.04	0.04	0.04	0.04	0.04	0.04
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w/o SCR	0.03	0.03	0.03	0.03	0.03	0.03
NOx, kg/h as NO2	19.87	15.77	21.78	17.22	23.15	18.21
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w/o SCR	20.43	19.28	21.03	20.06	21.41	20.51
NOx, mg/MJ (LHV) (including duct burner fuel) w/o SCR	15.76	15.50	15.85	15.61	15.91	15.67
NOx, mg/MJ (HHV) (including duct burner fuel) w/o SCR	14.19	13.96	14.27	14.05	14.32	14.11
NOx, ppmvd @15% O2 w/ SCR	3.50	3.50	3.50	3.50	3.50	3.50
NOx, ppmvd@ user defined oxygen w/ SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w SCR	4.41	4.22	4.41	4.27	4.45	4.31
NOx, ppmvw w SCR	3.94	3.78	4.03	3.91	4.09	3.98
NOx, lb/h as NO2 w/ SCR	17.34	13.99	18.89	15.18	20.01	15.98
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w SCR	0.01	0.01	0.01	0.01	0.01	0.01
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w SCR	0.01	0.01	0.01	0.01	0.01	0.01
NOx, kg/h as NO2	7.86	6.34	8.57	6.88	9.08	7.25
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w SCR	8.09	7.76	8.27	8.02	8.40	8.16
NOx, mg/MJ (LHV) (including duct burner fuel) w SCR	6.24	6.24	6.24	6.24	6.24	6.24
NOx, mg/MJ (HHV) (including duct burner fuel) w SCR	5.62	5.62	5.62	5.62	5.62	5.62
SCR NH3 slip, ppmvd @15% O2	10.00	10.00	10.00	10.00	10.00	10.00
SCR NH3 slip, lb/h	18.34	14.79	19.98	16.05	21.17	16.90
CO, ppmvd @ 15% O2 w/o Catalyst	11.90	12.44	11.90	12.31	11.81	12.18
CO, ppmvd @ user defined O2 w/o Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/o Catalyst	15.00	15.00	15.00	15.00	15.00	15.00
CO, ppmvw w/o Catalyst	13.39	13.44	13.70	13.74	13.80	13.83
CO, lb/h w/o Catalyst	37.67	31.79	41.05	34.12	43.16	35.53
CO, lb/MBtu (LHV) (incl. duct burner fuel) w/o SCR	0.03	0.03	0.03	0.03	0.03	0.03
CO, lb/MBtu (HHV) (incl. duct burner fuel) w/o SCR	0.03	0.03	0.03	0.03	0.03	0.03
CO Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%
CO, ppmvd @ 15% O2 w/ Catalyst	11.90	12.44	11.90	12.31	11.81	12.18
CO, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/ Catalyst	15.00	15.00	15.00	15.00	15.00	15.00
CO, ppmvw w/ Catalyst	13.39	13.44	13.70	13.74	13.80	13.83
CO, lb/h w/ Catalyst	35.88	30.28	39.10	32.49	41.10	33.84
CO, lb/MBtu (LHV) (incl. duct burner fuel) w SCR	0.030	0.031	0.030	0.031	0.030	0.031
CO, lb/MBtu (HHV) (incl. duct burner fuel) w SCR	0.027	0.028	0.027	0.028	0.027	0.028
SO2, ppmvd@15% O2 (with no SO2 oxidation)	0.12	0.12	0.12	0.12	0.12	0.12
SO2, ppmvd at user defined O2 (with no SO2 oxidation)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
SO2, ppmvd (with no SO2 oxidation)	0.15	0.14	0.15	0.14	0.15	0.14
SO2, ppmvw (with no SO2 oxidation)	0.13	0.13	0.13	0.13	0.14	0.13
SO2, lb/h (with no SO2 oxidation)	0.85	0.68	0.92	0.74	0.98	0.78
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	8	9	10	11	12	13
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9	DLN/9
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	75%	50%	75%	50%	75%	50%
Ambient Temperature, F	95	95	59	59	20	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	148,020	128,570	159,780	140,780	161,900	142,180
Heat Recovery Steam Generator Stack Emissions - continued						
NOTE: UHC calculations do NOT include the effect of any oxidation in the CO catalyst.						
UHC, ppmvd @ 15% O_2	6.22	6.48	6.08	6.27	5.99	6.16
UHC, ppmvd @ user defined O_2	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
UHC, ppmvd	7.84	7.82	7.68	7.64	7.61	7.59
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00	7.00
UHC, lb/h as CH_4	11.28	9.49	12.01	9.96	12.54	10.30
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.009	0.010	0.009	0.010	0.009	0.009
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.009	0.009	0.008	0.009	0.008	0.008
VOC, ppmvd @ 15% O_2 w/o Catalyst	1.24	1.30	1.22	1.25	1.20	1.23
VOC, ppmvd @ user defined O_2 w/o CO catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/o Catalyst	1.57	1.56	1.53	1.53	1.52	1.52
VOC, ppmvw w/o Catalyst	1.40	1.40	1.40	1.40	1.40	1.40
VOC, lb/h as CH_4 w/o Catalyst	2.26	1.90	2.40	1.99	2.51	2.08
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w/o CO catalyst	0.0019	0.0020	0.0018	0.0019	0.0018	0.0019
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w/o CO catalyst	0.0017	0.0018	0.0017	0.0017	0.0016	0.0017
VOC Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%
VOC, ppmvd @ 15% O_2 w/ Catalyst	1.24	1.30	1.22	1.25	1.20	1.23
VOC, ppmvd @ user defined O_2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/ Catalyst	1.57	1.56	1.53	1.53	1.52	1.52
VOC, ppmvw w/ Catalyst	1.40	1.40	1.40	1.40	1.40	1.40
VOC, lb/h as CH_4 w/ Catalyst	2.15	1.81	2.29	1.90	2.39	1.96
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w CO catalyst	0.0018	0.0019	0.0018	0.0018	0.0017	0.0018
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w CO catalyst	0.0016	0.0017	0.0016	0.0016	0.0016	0.0016
Particulate without the effect of SO_2 oxidation and SCR catalysts						
Particulates, lb/h (front half catch only)	9.5	9.5	9.5	9.5	9.5	9.5
Particulates, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.0079	0.0098	0.0073	0.0090	0.0069	0.0086
Particulates, lb/h (front and back half catch)	18.9	18.9	18.9	18.9	18.9	18.9
Particulates, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.016	0.020	0.015	0.018	0.014	0.017
PM10, lb/h (front half catch only)	9.5	9.5	9.5	9.5	9.5	9.5
PM10, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.008	0.010	0.007	0.009	0.007	0.009
PM10, lb/h (front and back half catch)	18.9	18.9	18.9	18.9	18.9	18.9
PM10, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.016	0.020	0.015	0.018	0.014	0.017
Particulate including the effect of SO_2 oxidation and SCR catalysts [includes $2(NH_4SO_4)$]						
Particulates, lb/h (front half catch only)	9.8	9.7	9.8	9.7	9.8	9.7
Particulates, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.0082	0.0101	0.0075	0.0093	0.0071	0.0088
Particulates, lb/h (front and back half catch)	19.2	19.1	19.2	19.2	19.2	19.2
Particulates, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.016	0.020	0.015	0.018	0.014	0.017
PM10, lb/h (front half catch only)	9.8	9.7	9.8	9.7	9.8	9.7
PM10, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.008	0.010	0.008	0.009	0.007	0.009
PM10, lb/h (front and back half catch)	19.2	19.1	19.2	19.2	19.2	19.2
PM10, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.016	0.020	0.015	0.018	0.014	0.017
NOTE: SO_2 to SO_3 conversion rate (assumed), wt%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
SO_3 conversion rate (assumed) to ammonium sulfates [$2(NH_4SO_4)$]	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Remaining SO_2 in Exhaust Gas, lb/h	0.76	0.62	0.83	0.67	0.88	0.70
Amount of SO_2 converted to SO_3	0.08	0.07	0.09	0.07	0.10	0.08
Maximum Exhaust Gas ammonium sulfate [$2(NH_4SO_4)$], lb/h	0.30	0.24	0.33	0.26	0.35	0.28
Maximum H_2SO_4 (assuming 100% conversion from SO_3 to H_2SO_4), lb/hr	0.13	0.10	0.14	0.11	0.15	0.12
Stack Exit Temperature, F	198	190	194	185	194	185
Stack Diameter, ft (estimated)	19	19	19	19	19	19
Stack Flow, lb/h	2,691,000	2,265,000	2,890,000	2,397,000	3,025,000	2,486,000
Stack Flow, scfm	605,027	508,870	644,470	534,132	672,558	552,306
Stack Flow, acfm	765,590	635,710	811,127	662,371	846,496	685,307
Stack Exit Velocity, ft/s	45.0	37.4	47.7	38.9	49.8	40.3
Selective Catalytic Reduction (SCR)						
NOx Removed, lb/h as NO_2	26.5	20.8	29.1	22.8	31.0	24.2
NOx Removed, percent	60.4%	59.8%	60.6%	60.0%	60.8%	60.2%
NH_3 Slip, lb/h	18.3	14.8	20.0	16.1	21.2	16.9
Total NH_3 consumption, lb/h (1:1 stoichiometric ratio, incl. slip)	28.1	22.5	30.8	24.5	32.6	25.8
Adjusted Stack Diameter (ft) estimated	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	50.1	41.6	53.1	43.4	56.4	44.9

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The combustion turbine generator performance and emissions is based on a General Electric performance estimate provided by JEA.
3. The combustion turbine emissions estimate may include margin as indicated in the table.

   Where catalysts are involved to reduce emissions, the margin applied to the CTG emissions only affects the amount of emissions removed, but not the stack emissions.

4. UHC calculations do not include the effects of any oxidation in the CO catalyst. It was assumed that the VOC/UHC ratio is 20% for natural gas firing, and 50% for distillate oil firing.
5. It was assumed that the front and back half catch of CTG particulate emissions is twice the amount of front half catch only.
6. Duct Burner emissions are Black & Veatch estimates based on typical vendor data.
7. It was assumed that ammonium sulfate is measured as front half particulates. The assumption that 100% SO_3 is converted to ammonium sulfates results in "worst case" particulate emissions.
8. The maximum amount of ammonium sulfates and sulfuric acid shown in the table can not occur in parallel at the same time.

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Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Ambient Temperature, F	95.0	59.0	20.0	95.0	95.0	59.0	20.0
Ambient Temperature, C	35.0	15.0	(6.7)	35.0	35.0	15.0	(6.7)
Ambient Relative Humidity, %	60.0	60.0	60.0	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
Atmospheric Pressure, bar(a)	1.013	1.013	1.013	1.013	1.013	1.013	1.013
CTG Compressor Inlet Dry Bulb Temperature, F	95.0	59.0	20.0	84.5	95.0	59.0	20.0
CTG Compressor Inlet Temperature, C	35.0	15.0	(6.7)	29.2	35.0	15.0	(6.7)
CTG Compr. Inlet Relative Humidity, %	60.1	60.2	60.3	92.6	60.1	60.2	60.3
CTG Inlet Air Conditioning Included?	No	No	No	Yes (Evap. Cooler)	No	No	No
Inlet Loss, in. H2O	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Inlet Loss, mm. H2O	88.9	88.9	88.9	88.9	88.9	88.9	88.9
Exhaust Loss, in. H2O	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Exhaust Loss, mm. H2O	381.0	381.0	381.0	381.0	381.0	381.0	381.0
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	75%	75%	75%
Gross CTG Output, kW	157,970	179,580	190,140	165,200	118,500	134,680	142,580
Gross CTG Heat Rate, Btu/kWh (LHV)	10,380	10,140	10,170	10,250	11,320	10,970	10,980
Gross CTG Heat Rate, KJ/KWh (LHV)	10,951	10,698	10,730	10,814	11,943	11,574	11,585
Gross CTG Heat Rate, kJ/kWh (HHV)	11,055	10,799	10,831	10,916	12,056	11,683	11,694
Gross CTG Heat Rate, KJ/KWh (HHV)	11,664	11,394	11,427	11,517	12,720	12,326	12,338
CTG Heat Input, MBtu/h (LHV)	1,639.7	1,820.9	1,933.7	1,693.3	1,341.4	1,477.4	1,565.5
CTG Heat Input, GJ/h (LHV)	1,730.0	1,921.2	2,040.2	1,786.5	1,415.3	1,558.8	1,651.7
CTG Heat Input, MBtu/h (HHV)	1,746.3	1,939.3	2,059.4	1,803.4	1,428.6	1,573.5	1,667.3
CTG Heat Input, GJ/h (HHV)	1,842.5	2,046.1	2,172.8	1,902.7	1,507.3	1,660.1	1,759.1
CTG Water Injection Flow, lb/h	93,590	119,700	130,530	100,900	69,010	90,620	100,950
CTG Water Injection Flow, kg/h	42,452	54,295	59,207	45,767	31,302	41,105	45,790
CTG Steam Injection Flow, lb/h	0	0	0	0	0	0	0
CTG Steam Injection Flow, kg/h	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
CTG Exhaust Flow, lb/h	3,365,000	3,683,000	3,914,000	3,444,950	2,693,000	2,827,000	2,925,000
CTG Exhaust Flow, kg/h	1,526,338	1,670,561	1,775,361	1,562,603	1,221,524	1,282,306	1,326,758
CTG Exhaust Temperature, F	1,140	1,105	1,075	1,132	1,207	1,201	1,190
CTG Exhaust Temperature, C	615.6	596.1	579.4	611.1	652.8	649.4	643.3
CTG Exhaust Enthalpy, Btu/lb	284.00	280.95	281.28	282.65	303.25	309.19	315.53
CTG Exhaust Enthalpy, kJ/lb	299.64	296.42	296.77	298.21	319.95	326.21	332.90
CTG Exhaust Enthalpy Reference Temperature, F	95	59	20	95	95	59	20
CTG Exhaust Enthalpy Reference Temperature, C	35.0	15.0	(6.7)	35.0	35.0	15.0	(6.7)
CTG Exhaust Heat, MBtu/h	955.7	1,034.7	1,100.9	973.7	816.7	874.1	922.9
CTG Exhaust Heat, GJ/h	1,008.3	1,091.7	1,161.5	1,027.3	861.6	922.2	973.7
CTG Exhaust Heat/CTG Output, kW/kW	177.3%	168.9%	169.7%	172.7%	202.0%	190.2%	189.7%
Total CTG Fuel Flow, lb/h	88400	98160	104240	91280	72310	79650	84400
CTG Fuel Temperature, F	60	60	60	60	60	60	60
CTG Fuel LHV, Btu/lb	18,550	18,550	18,550	18,550	18,550	18,550	18,550
CTG Fuel LHV, kJ/lb	43,147	43,147	43,147	43,147	43,147	43,147	43,147
CTG Fuel HHV, Btu/lb	19,756	19,756	19,756	19,756	19,756	19,756	19,756
CTG Fuel HHV, kJ/lb	45,952	45,952	45,952	45,952	45,952	45,952	45,952
HHV/LHV Ratio	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%
C	85.59%	85.59%	85.59%	85.59%	85.59%	85.59%	85.59%
H2	14.35%	14.35%	14.35%	14.35%	14.35%	14.35%	14.35%
N2	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	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

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Combustion Turbine Exhaust Emissions							
CTG Exhaust Analysis (Volume Basis - Wet)							
Ar	0.88%	0.89%	0.90%	0.88%	0.88%	0.89%	0.90%
CO2	5.27%	5.37%	5.38%	5.30%	5.39%	5.68%	5.82%
H2O	12.70%	11.39%	10.81%	13.29%	12.49%	11.63%	11.44%
N2	70.17%	71.23%	71.69%	69.72%	70.38%	71.17%	71.38%
O2	10.98%	11.11%	11.22%	10.81%	10.85%	10.63%	10.46%
SO2	0.00115%	0.00118%	0.00118%	0.00116%	0.00118%	0.00124%	0.00127%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
NOx, ppmvd @15% O2	42.00	42.00	42.00	42.00	42.00	42.00	42.00
NOx, ppmvd @ 15% O2	42.00	42.00	42.00	42.00	42.00	42.00	42.00
NOx, ppmvd	59.00	59.30	59.00	59.78	60.24	62.87	64.33
NOx, ppmvw (wet - uncorrected exhaust gas)	51.51	52.54	52.62	51.84	52.71	55.56	56.97
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Additonal Percent Margin Included in NOx Emissions below	5%	5%	5%	5%	5%	5%	5%
NOx, lb/h as NO2	298.83	331.49	351.96	308.33	244.46	269.17	285.16
NOx, lb/MBtu (LHV)	0.18	0.18	0.18	0.18	0.18	0.18	0.18
NOx, lb/MBtu (HHV)	0.17	0.17	0.17	0.17	0.17	0.17	0.17
NOx, mg/Nm3 as NO2 (dry, 15% O2)	90.84	90.81	90.80	90.84	90.91	90.88	90.86
NOx, mg/Nm3 as NO2 (dry, 15% O2)	90.84	90.81	90.80	90.84	90.91	90.88	90.86
NOx, mg/Nm3 as NO2 (dry)	127.61	128.22	127.56	129.29	130.38	136.04	139.17
NOx, mg/Nm3 as NO2 (wet - uncorrected exhaust flow)	111.41	113.62	113.77	112.11	114.10	120.21	123.25
NOx, mg/MJ (LHV)	78.30	78.27	78.25	78.28	78.35	78.33	78.31
NOx, mg/MJ (HHV)	73.52	73.49	73.47	73.50	73.57	73.55	73.53
CO, ppmvd @ 15% O2	14.24	14.17	14.24	14.05	13.94	13.36	13.06
CO, ppmvd @ 15% O2	14.24	14.17	14.24	14.05	13.95	13.36	13.06
CO, ppmvd	20.00	20.00	20.00	20.00	20.00	20.00	20.00
CO, ppmvw (wet - uncorrected exhaust gas)	17.46	17.72	17.84	17.34	17.50	17.67	17.71
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in CO Emissions below	5%	5%	5%	5%	5%	5%	5%
CO, lb/h	61.43	67.86	72.43	62.59	49.21	51.94	53.79
CO, lb/MBtu (LHV)	0.04	0.04	0.04	0.04	0.04	0.04	0.03
CO, lb/MBtu (HHV)	0.04	0.03	0.04	0.03	0.03	0.03	0.03
CO, mg/Nm3 (wet - uncorrected exhaust flow)	22.92	23.26	23.41	22.76	22.97	23.19	23.25
CO, mg/Nm3 (dry)	26.25	26.25	26.25	26.25	26.25	26.25	26.25
CO, mg/Nm3 (dry, 15% O2)	18.69	18.59	18.68	18.44	18.30	17.54	17.14
CO, mg/Nm3 (dry, 15% O2)	18.69	18.59	18.68	18.44	18.30	17.54	17.14
CO, mg/MJ (LHV)	16.11	16.02	16.10	15.89	15.77	15.11	14.77
CO, mg/MJ (HHV)	15.12	15.04	15.12	14.92	14.81	14.19	13.87
NOTE: SO2 estimate does not include the effects of SO2 oxidation							
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	9.40	9.40	9.40	9.40	9.40	9.40	9.40
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	9.40	9.40	9.40	9.40	9.40	9.40	9.40
SO2, ppmvd (with no SO2 oxidation)	13.20	13.27	13.20	13.38	13.48	14.07	14.39
SO2, ppmvw (with no SO2 oxidation)(wet - uncorrected exhaust gas)	11.53	11.76	11.78	11.60	11.80	12.43	12.75
SO2 Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in SO2 Emissions below	5%	5%	5%	5%	5%	5%	5%
SO2, lb/h (with no SO2 oxidation)	92.73	102.97	109.35	95.75	75.85	83.55	88.54
SO2, lb/MBtu (LHV) (with no SO2 oxidation)	0.0566	0.0565	0.0565	0.0565	0.0565	0.0566	0.0566
SO2, lb/MBtu (HHV) (with no SO2 oxidation)	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531
SO2, mg/Nm3 (wet - uncorrected exhaust flow) (with no SO2 oxidation)	34.60	35.29	35.35	34.82	35.40	37.31	38.27
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	28.21	28.21	28.21	28.21	28.21	28.21	28.21
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	28.21	28.21	28.21	28.21	28.21	28.21	28.21
SO2, mg/Nm3 (dry) (with no SO2 oxidation)	39.63	39.83	39.63	40.15	40.46	42.23	43.21
SO2, mg/MJ (LHV) (with no SO2 oxidation)	24.31	24.31	24.31	24.31	24.31	24.31	24.31
SO2, mg/MJ (HHV) (with no SO2 oxidation)	22.83	22.83	22.83	22.83	22.83	22.83	22.83

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Combustion Turbine Exhaust Emissions - continued							
UHC, ppmvd @ 15% O2	5.71	5.60	5.59	5.67	5.58	5.29	5.16
UHC, ppmvd @ 15% O2	5.71	5.60	5.59	5.67	5.58	5.29	5.16
UHC, ppmvd	8.02	7.90	7.85	8.07	8.00	7.92	7.90
UHC, ppmvw (wet - uncorrected exhaust gas)	7.00	7.00	7.00	7.00	7.00	7.00	7.00
UHC Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in UHC Emissions Below	5%	5%	5%	5%	5%	5%	5%
UHC, lb/h as CH4	14.10	15.35	16.28	14.47	11.27	11.78	12.17
UHC, lb/MBtu as CH4 (LHV)	0.0088	0.0084	0.0084	0.0085	0.0084	0.0080	0.0078
UHC, lb/MBtu as CH4 (HHV)	0.0081	0.0079	0.0079	0.0080	0.0079	0.0075	0.0073
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.29	4.21	4.20	4.26	4.19	3.98	3.88
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.29	4.21	4.20	4.26	4.19	3.98	3.88
UHC, mg/Nm3 as CH4 (dry)	6.03	5.94	5.90	6.07	6.01	5.95	5.94
UHC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	5.26	5.26	5.26	5.26	5.26	5.26	5.26
UHC, mg/MJ as CH4 (LHV)	3.70	3.62	3.62	3.67	3.61	3.43	3.34
UHC, mg/MJ as CH4 (HHV)	3.47	3.40	3.40	3.45	3.39	3.22	3.14
VOC percentage of UHC	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
VOC, ppmvd @ 15% O2	2.9	2.8	2.8	2.8	2.8	2.6	2.6
VOC, ppmvd @ 15% O2	2.9	2.8	2.8	2.8	2.8	2.6	2.6
VOC, ppmvd	4.01	3.95	3.92	4.04	4.00	3.96	3.95
VOC, ppmvw (wet - uncorrected exhaust flow)	3.50	3.50	3.50	3.50	3.50	3.50	3.50
VOC Massflow Added to Match CTG Manufacturer's VOC Emissions Estimate	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Additional Percent Margin Included in VOC Emissions below	5%	5%	5%	5%	5%	5%	5%
VOC, lb/h as CH4	7.05	7.68	8.14	7.24	5.64	5.89	6.09
VOC, lb/MBtu as CH4 (LHV)	0.0043	0.0042	0.0042	0.0043	0.0042	0.0040	0.0039
VOC, lb/MBtu as CH4 (HHV)	0.0040	0.0040	0.0040	0.0040	0.0039	0.0037	0.0037
VOC, mg/Nm3 as CH4 (dry, 15% O2)	2.15	2.10	2.10	2.13	2.10	1.99	1.94
VOC, mg/Nm3 as CH4 (dry, 15% O2)	2.15	2.10	2.10	2.13	2.10	1.99	1.94
VOC, mg/Nm3 as CH4 (dry)	3.01	2.97	2.95	3.03	3.01	2.98	2.97
VOC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	2.63	2.63	2.63	2.63	2.63	2.63	2.63
VOC, mg/MJ as CH4 (LHV)	1.85	1.81	1.81	1.84	1.81	1.71	1.67
VOC, mg/MJ as CH4 (HHV)	1.74	1.70	1.70	1.72	1.70	1.61	1.57
Percent Margin included in Particulates Emissions below	5%	5%	5%	5%	5%	5%	5%
Particulates, lb/h (front half catch only)	17.85	17.85	17.85	17.85	17.85	17.85	17.85
Particulates, lb/h (front and back half catch)	35.70	35.70	35.70	35.70	35.70	35.70	35.70
Particulates, lb/MBtu (LHV) (front half catch only)	0.0109	0.0098	0.0092	0.0105	0.0133	0.0121	0.0114
Particulates, lb/MBtu (HHV) (front half catch only)	0.0102	0.0092	0.0087	0.0099	0.0125	0.0113	0.0107
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	5.43	4.89	4.60	5.26	6.64	6.03	5.69
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	5.43	4.89	4.60	5.26	6.64	6.03	5.69
Particulates, mg/Nm3 (dry) (front half catch only)	7.63	6.90	6.47	7.49	9.52	9.02	8.71
Particulates, mg/Nm3 (wet - uncorrected exhaust flow) (front half catch only)	6.66	6.12	5.77	6.49	8.33	7.97	7.71
Particulates, mg/MJ (LHV) (front half catch only)	4.68	4.21	3.97	4.53	5.72	5.19	4.90
Particulates, mg/MJ (HHV) (front half catch only)	4.39	3.96	3.73	4.26	5.37	4.88	4.60
Percent Margin included in PM10 Emissions below	0%	0%	0%	0%	0%	0%	0%
PM10, lb/h (front half catch only)	17.00	17.00	17.00	17.00	17.00	17.00	17.00
PM10, lb/h (front and back half catch)	34.00	34.00	34.00	34.00	34.00	34.00	34.00
PM10, lb/MBtu (LHV) (front and back half catch)	0.02	0.02	0.02	0.02	0.03	0.02	0.02
PM10, lb/MBtu (HHV) (front and back half catch)	0.02	0.02	0.02	0.02	0.02	0.02	0.02
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	*10.34*	*9.31*	*8.77*	*10.02*	*12.64*	*11.48*	*10.83*
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	10.34	9.31	8.77	10.02	12.64	11.48	10.83
PM10, mg/Nm3 (dry) (front and back half catch)	14.53	13.15	12.32	14.26	18.13	17.18	16.59
PM10, mg/Nm3 (wet - uncorrected exhaust flow) (front and back half catch)	12.68	11.65	10.99	12.36	15.87	15.18	14.70
PM10, mg/MJ (LHV) (front and back half catch)	8.91	8.03	7.56	8.63	10.90	9.89	9.34
PM10, mg/MJ (HHV) (front and back half catch)	8.37	7.54	7.10	8.11	10.23	9.29	8.77
CTG Wet (Total) Exhaust Gas Analysis							
Molecular Wt, lb/mol	28.13	28.29	28.35	28.07	28.17	28.29	28.33
Molecular Wt, kg/mol	12.76	12.83	12.86	12.73	12.78	12.83	12.85
Gas Constant, ft-lbf/lbm-R	54.921	54.622	54.498	55.041	54.852	54.610	54.539
Specific Volume, ft^3/lb	40.05	38.96	38.13	39.94	41.68	41.35	41.02
Specific Volume, m^3/kg	2.50	2.43	2.38	2.49	2.60	2.58	2.56
Exhaust Gas Flow, acfm	2,246,138	2,391,495	2,487,347	2,293,188	1,870,737	1,948,274	1,999,725
Specific Volume, scf/lb	13.49	13.41	13.38	13.52	13.47	13.41	13.39
Exhaust Gas Flow, scfm	756,564	823,151	872,822	776,262	604,579	631,835	652,763
Specific Volume, Nm3/kg	0.7966	0.7922	0.7904	0.7983	0.7956	0.7921	0.7910
Exhaust Gas Flow, Nm3/s	337.74	367.62	389.79	346.51	269.96	282.14	291.52

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Duct Burner Emissions							
Duct Burner Heat Input, MBtu/h (LHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (LHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (HHV) (margin included)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	18,550	18,550	18,550	18,550	18,550	18,550	18,550
Duct Burner Fuel HHV, kJ/kg	43,147	43,147	43,147	43,147	43,147	43,147	43,147
Duct Burner Fuel HHV, Btu/lb	19,756	19,756	19,756	19,756	19,756	19,756	19,756
Duct Burner Fuel HHV, kJ/kg	45,952	45,952	45,952	45,952	45,952	45,952	45,952
Duct Burner Fuel Composition (Ultimate Analysis by Weight)							
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.59%	85.59%	85.59%	85.59%	85.59%	85.59%	85.59%
H2	14.35%	14.35%	14.35%	14.35%	14.35%	14.35%	14.35%
N2	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	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
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner NOx, kg/kJ (HHV)	0.034	0.034	0.034	0.034	0.034	0.034	0.034
Duct Burner CO, lb/MBtu (HHV)	0.100	0.100	0.100	0.100	0.100	0.100	0.100
Duct Burner CO, kg/kJ (HHV)	0.043	0.043	0.043	0.043	0.043	0.043	0.043
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner UHC, kg/kJ (HHV)	0.026	0.026	0.026	0.026	0.026	0.026	0.026
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Duct Burner VOC (as CH4), kg/kJ (HHV)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner Particulate, kg/kJ (HHV) (front half catch only)	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner Particulate, lb/MBtu (HHV) (front and back half catch)	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Duct Burner Particulate, kg/kJ (HHV) (front and back half catch)	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Duct Burner PM10, kg/kJ (HHV) (front half catch only)	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Duct Burner PM10, kg/kJ (HHV) (front and back half catch)	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Total SO2, lb/h from Duct Burner	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total SO2, kg/h from Duct Burner	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB NOx, kg/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB CO, kg/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB UHC (as CH4), kg/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB VOC (as CH4), kg/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, kg/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB Particulate, kg/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, kg/h (front half catch only)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DB PM10, kg/h (front and back half catch)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Heat Recovery Steam Generator Stack Emissions							
NOTE: Exhaust Analysis does not include the effects of post combustion control							
Stack Exhaust Analysis (Volume Basis - Wet)							
Ar	0.88%	0.89%	0.90%	0.88%	0.88%	0.89%	0.90%
CO2	5.27%	5.37%	5.38%	5.30%	5.39%	5.68%	5.82%
H2O	12.70%	11.39%	10.81%	13.29%	12.49%	11.63%	11.44%
N2	70.17%	71.23%	71.69%	69.72%	70.38%	71.17%	71.38%
O2	10.98%	11.11%	11.22%	10.81%	10.85%	10.63%	10.46%
SO2	0.00115%	0.00118%	0.00118%	0.00116%	0.00118%	0.00124%	0.00127%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Emissions							
NOx, ppmvd @15% O2 w/o SCR	42.00	42.00	42.00	42.00	42.00	42.00	42.00
NOx, ppmvd@ user defined oxygen w/o SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w/o SCR	59.00	59.30	59.00	59.78	60.24	62.87	64.33
NOx, ppmvw w/o SCR	51.51	52.54	52.62	51.84	52.71	55.56	56.97
NOx, lb/h as NO2 w/o SCR	298.63	331.49	351.96	308.33	244.46	269.17	285.16
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w/o SCR	0.18	0.18	0.18	0.18	0.18	0.18	0.18
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w/o SCR	0.17	0.17	0.17	0.17	0.17	0.17	0.17
NOx, kg/h as NO2	135.46	150.36	159.65	139.86	110.88	122.09	129.35
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w/o SCR	111.41	113.62	113.77	112.11	114.10	120.21	123.25
NOx, mg/MJ (LHV) (including duct burner fuel) w/o SCR	78.30	78.27	78.25	78.28	78.35	78.33	78.31
NOx, mg/MJ (HHV) (including duct burner fuel) w/o SCR	73.52	73.49	73.47	73.50	73.57	73.55	73.53
NOx, ppmvd @15% O2 w/ SCR	15.00	15.00	15.00	15.00	15.00	15.00	15.00
NOx, ppmvd@ user defined oxygen w/ SCR	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
NOx, ppmvd w SCR	21.07	21.18	21.07	21.35	21.51	22.45	22.97
NOx, ppmvw w SCR	18.40	18.76	18.79	18.51	18.83	19.84	20.35
NOx, lb/h as NO2 w/ SCR	101.23	112.41	119.37	104.53	82.81	91.21	96.65
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w SCR	0.06	0.06	0.06	0.06	0.06	0.06	0.06
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w SCR	0.06	0.06	0.06	0.06	0.06	0.06	0.06
NOx, kg/h as NO2	45.92	50.99	54.15	47.42	37.56	41.37	43.84
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w SCR	37.77	38.53	38.59	38.01	38.85	40.73	41.77
NOx, mg/MJ (LHV) (including duct burner fuel) w SCR	26.54	26.54	26.54	26.54	26.54	26.54	26.54
NOx, mg/MJ (HHV) (including duct burner fuel) w SCR	24.92	24.92	24.92	24.92	24.92	24.92	24.92
SCR NH3 slip, ppmvd @15% O2	9.00	9.00	9.00	9.00	9.00	9.00	9.00
SCR NH3 slip, lb/h	22.49	24.97	26.52	23.22	18.39	20.26	21.47
CO, ppmvd @ 15% O2 w/o Catalyst	14.24	14.17	14.24	14.05	13.95	13.36	13.06
CO, ppmvd @ user defined O2 w/o Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/o Catalyst	20.00	20.00	20.00	20.00	20.00	20.00	20.00
CO, ppmvw w/o Catalyst	17.46	17.72	17.84	17.34	17.50	17.67	17.71
CO, lb/h w/o Catalyst	61.43	67.86	72.43	62.59	49.21	51.94	53.79
CO, lb/MBtu (LHV) (incl. duct burner fuel) w/o SCR	0.04	0.04	0.04	0.04	0.04	0.04	0.03
CO, lb/MBtu (HHV) (incl. duct burner fuel) w/o SCR	0.04	0.03	0.04	0.03	0.03	0.03	0.03
CO Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%	0%
CO, ppmvd @ 15% O2 w/ Catalyst	14.24	14.17	14.24	14.05	13.95	13.36	13.06
CO, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
CO, ppmvd w/ Catalyst	20.00	20.00	20.00	20.00	20.00	20.00	20.00
CO, ppmvw w/ Catalyst	17.46	17.72	17.84	17.34	17.50	17.67	17.71
CO, lb/h w/ Catalyst	58.50	64.63	68.98	59.61	46.87	49.47	51.23
CO, lb/MBtu (LHV) (incl. duct burner fuel) w SCR	0.036	0.035	0.036	0.035	0.035	0.033	0.033
CO, lb/MBtu (HHV) (incl. duct burner fuel) w SCR	0.033	0.033	0.033	0.033	0.033	0.031	0.031
SO2, ppmvd@15% O2 (with no SO2 oxidation)	9.40	9.40	9.40	9.40	9.40	9.40	9.40
SO2, ppmvd at user defined O2 (with no SO2 oxidation)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
SO2, ppmvd (with no SO2 oxidation)	13.20	13.27	13.20	13.38	13.48	14.07	14.39
SO2, ppmvw (with no SO2 oxidation)	11.53	11.76	11.78	11.60	11.80	12.43	12.75
SO2, lb/h (with no SO2 oxidation)	92.73	102.97	109.35	95.75	75.85	83.55	88.54
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0566	0.0565	0.0565	0.0565	0.0565	0.0566	0.0566
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	*0.0531*	*0.0531*	*0.0531*	*0.0531*	*0.0531*	*0.0531*	*0.0531*

Jacksonville Electric Authority
Brandy Branch 2x1 7FA Combined Cycle Project
Estimated Combustion Turbine and Heat Recovery Steam Generator Emissions, Rev.5

Preparer's Initials: UZ
10/26/00

Case Number	14	15	16	17	18	19	20
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	100%	100%	100%	100%	75%	75%	75%
Ambient Temperature, F	95	59	20	95	95	59	20
HRSG Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	172,650	187,310	189,870	175,490	149,830	162,700	165,920
Heat Recovery Steam Generator Stack Emissions - continued							
NOTE: UHC calculations do NOT include the effect of any oxidation in the CO catalyst.							
UHC, ppmvd @ 15% O2	5.71	5.60	5.59	5.67	5.58	5.29	5.16
UHC, ppmvd @ user defined O2	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
UHC, ppmvd	8.02	7.90	7.85	8.07	8.00	7.92	7.90
UHC, ppmvw	7.00	7.00	7.00	7.00	7.00	7.00	7.00
UHC, lb/h as CH4	14.10	15.35	16.28	14.47	11.27	11.78	12.17
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.009	0.008	0.008	0.009	0.008	0.008	0.008
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.008	0.008	0.008	0.008	0.008	0.007	0.007
VOC, ppmvd @ 15% O2 w/o Catalyst	2.85	2.80	2.79	2.84	2.79	2.65	2.58
VOC, ppmvd @ user defined O2 w/o CO catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/o Catalyst	4.01	3.95	3.92	4.04	4.00	3.96	3.95
VOC, ppmvw w/o Catalyst	3.50	3.50	3.50	3.50	3.50	3.50	3.50
VOC, lb/h as CH4 w/o Catalyst	7.05	7.68	8.14	7.24	5.64	5.89	6.09
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w/o CO catalyst	0.0043	0.0042	0.0042	0.0043	0.0042	0.0040	0.0039
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w/o CO catalyst	0.0040	0.0040	0.0040	0.0040	0.0039	0.0037	0.0037
VOC Reduction % w/ Catalyst	0%	0%	0%	0%	0%	0%	0%
VOC, ppmvd @ 15% O2 w/ Catalyst	2.85	2.80	2.79	2.84	2.79	2.65	2.58
VOC, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
VOC, ppmvd w/ Catalyst	4.01	3.95	3.92	4.04	4.00	3.96	3.95
VOC, ppmvw w/ Catalyst	3.50	3.50	3.50	3.50	3.50	3.50	3.50
VOC, lb/h as CH4 w/ Catalyst	6.72	7.31	7.75	6.89	5.37	5.61	5.80
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w CO catalyst	0.0041	0.0040	0.0040	0.0041	0.0040	0.0038	0.0037
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w CO catalyst	0.0038	0.0038	0.0038	0.0038	0.0038	0.0036	0.0035
Particulate without the effect of SO2 oxidation and SCR catalysts							
Particulates, lb/h (front half catch only)	17.9	17.9	17.9	17.9	17.9	17.9	17.9
Particulates, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.0109	0.0098	0.0092	0.0105	0.0133	0.0121	0.0114
Particulates, lb/h (front and back half catch)	35.7	35.7	35.7	35.7	35.7	35.7	35.7
Particulates, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.022	0.020	0.018	0.021	0.027	0.024	0.023
PM10, lb/h (front half catch only)	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PM10, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.010	0.009	0.009	0.010	0.013	0.012	0.011
PM10, lb/h (front and back half catch)	34.0	34.0	34.0	34.0	34.0	34.0	34.0
PM10, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.021	0.019	0.018	0.020	0.025	0.023	0.022
Particulate including the effect of SO2 oxidation and SCR catalysts [includes 2(NH4SO4)]							
Particulates, lb/h (front half catch only)	41.6	44.3	45.9	42.4	37.3	39.3	40.6
Particulates, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.0254	0.0243	0.0237	0.0250	0.0278	0.0266	0.0259
Particulates, lb/h (front and back half catch)	59.5	62.1	63.7	60.3	55.2	57.1	58.4
Particulates, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.036	0.034	0.033	0.036	0.041	0.039	0.037
PM10, lb/h (front half catch only)	40.8	43.4	45.0	41.6	36.5	38.4	39.7
PM10, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.025	0.024	0.023	0.025	0.027	0.026	0.025
PM10, lb/h (front and back half catch)	57.8	60.4	62.0	58.6	53.5	55.4	56.7
PM10, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.035	0.033	0.032	0.035	0.040	0.038	0.036
NOTE: SO2 to SO3 conversion rate (assumed), wt%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
SO3 conversion rate (assumed) to ammonium sulfates [2(NH4SO4)]	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Remaining SO2 in Exhaust Gas, lb/h	85.31	94.73	100.60	88.09	69.79	76.87	81.45
Amount of SO2 converted to SO3	7.42	8.24	8.75	7.66	6.07	6.68	7.08
Maximum Exhaust Gas ammonium sulfate [2(NH4SO4)], lb/h	23.78	26.41	28.05	24.56	19.46	21.43	22.71
Maximum H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/hr	11.36	12.61	13.39	11.73	9.29	10.23	10.84
Stack Exit Temperature, F	272	265	265	274	259	255	255
Stack Diameter, ft (estimated)	19	19	19	19	19	19	19
Stack Flow, lb/h	3,365,000	3,683,000	3,914,000	3,444,950	2,693,000	2,827,000	2,925,000
Stack Flow, scfm	756,564	823,151	872,822	776,262	604,579	631,835	652,763
Stack Flow, acfm	1,066,144	1,149,096	1,217,254	1,095,494	836,625	868,831	898,950
Stack Exit Velocity, ft/s	62.7	67.5	71.6	64.4	49.2	51.1	52.8
Selective Catalytic Reduction (SCR)							
NOx Removed, lb/h as NO2	197.4	219.1	232.6	203.8	161.7	178.0	188.5
NOx Removed, percent	66.1%	66.1%	66.1%	66.1%	66.1%	66.1%	66.1%
NH3 Slip, lb/h	22.5	25.0	26.5	23.2	18.4	20.3	21.5
Total NH3 consumption, lb/h (1:1 stoichiometric ratio, incl. slip)	95.6	106.1	112.6	98.7	78.2	86.1	91.3
Adjusted Stack Diameter (ft) estimated	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Stack Exit Velocity, ft/s	69.8	75.3	79.7	71.7	54.8	56.9	58.9

Notes:

1. The emissions estimates shown in the table above are per stack.

2. The combustion turbine generator performance and emissions is based on a General Electric performance estimate provided by JEA.

3. The combustion turbine emissions estimate may include margin as indicated in the table.

Where catalysts are involved to reduce emissions, the margin applied to the CTG emissions only effects the amount of emissions removed, but not the stack emissions.

4. UHC calculations do not include the effects of any oxidation in the CO catalyst. It was assumed that the VOC/UHC ratio is 20% for natural gas firing, and 50% for distillate oil firing.

5. It was assumed that the front and back half catch of CTG particulate emissions is twice the amount of front half catch only.

6. Duct Burner emissions are Black & Veatch estimates based on typical vendor data.

7. It was assumed that ammonium sulfate is measured as front half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.

8. The maximum amount of ammonium sulfates and sulfuric acid shown in the table can not occur in parallel at the same time.

Preparer: UZ Filepath: c:_projects\jea duct firing study\[exh_082700r5.xls]calculations Reviewer: UZ

Preparer's Initials: UZ

10/26/00

Project number 99262.0040

Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,360
Ambient Temperature, F	95.0	59.0	20.0
Ambient Temperature, C	35.0	15.0	(6.7)
Ambient Relative Humidity, %	60.0	60.0	60.0
Atmospheric Pressure, psia	14.690	14.690	14.690
Atmospheric Pressure, bar(a)	1.013	1.013	1.013
CTG Compressor Inlet Dry Bulb Temperature, F	95.0	59.0	20.0
CTG Compressor Inlet Temperature, C	35.0	15.0	(6.7)
CTG Compr. Inlet Relative Humidity, %	60.1	60.2	60.3
CTG Inlet Air Conditioning Included?	No	No	No
Inlet Loss, in. H2O	3.5	3.5	3.5
Inlet Loss, mm. H2O	88.9	88.9	88.9
Exhaust Loss, in. H2O	15.0	15.0	15.0
Exhaust Loss, mm. H2O	381.0	381.0	381.0
CTG Load Level (percent of Base Load)	50%	50%	50%
Gross CTG Output, kW	79,030	89,790	95,120
Gross CTG Heat Rate, Btu/kWh (LHV)	13,450	12,950	12,850
Gross CTG Heat Rate, KJ/KWh (LHV)	14,191	13,663	13,557
Gross CTG Heat Rate, kJ/kWh (HHV)	14,324	13,792	13,685
Gross CTG Heat Rate, KJ/KWh (HHV)	15,113	14,551	14,438
CTG Heat Input, MBtu/h (LHV)	1,063.0	1,162.8	1,222.3
CTG Heat Input, GJ/h (LHV)	1,121.5	1,226.8	1,289.6
CTG Heat Input, MBtu/h (HHV)	1,132.1	1,238.4	1,301.8
CTG Heat Input, GJ/h (HHV)	1,194.4	1,306.6	1,373.4
CTG Water Injection Flow, lb/h	46,070	61,970	68,710
CTG Water Injection Flow, kg/h	20,897	28,109	31,166
CTG Steam Injection Flow, lb/h	0	0	0
CTG Steam Injection Flow, kg/h	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	2,318,000	2,406,000	2,439,000
CTG Exhaust Flow, kg/h	1,051,427	1,091,343	1,106,312
CTG Exhaust Temperature, F	1,207	1,207	1,207
CTG Exhaust Temperature, C	652.8	652.8	652.8
CTG Exhaust Enthalpy, Btu/lb	300.97	308.44	318.00
CTG Exhaust Enthalpy, kJ/lb	317.54	325.42	335.51
CTG Exhaust Enthalpy Reference Temperature, F	95	59	20
CTG Exhaust Enthalpy Reference Temperature, C	35.0	15.0	(6.7)
CTG Exhaust Heat, MBtu/h	697.6	742.1	775.6
CTG Exhaust Heat, GJ/h	736.1	783.0	818.3
CTG Exhaust Heat/CTG Output, kW/kW	258.7%	242.2%	239.0%
Total CTG Fuel Flow, lb/h	57300	62680	65890
CTG Fuel Temperature, F	60	60	60
CTG Fuel LHV, Btu/lb	18,550	18,550	18,550
CTG Fuel LHV, kJ/lb	43,147	43,147	43,147
CTG Fuel HHV, Btu/lb	19,756	19,756	19,756
CTG Fuel HHV, kJ/lb	45,952	45,952	45,952
HHV/LHV Ratio	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)			
Ar	0.00%	0.00%	0.00%
C	85.59%	85.59%	85.59%
H2	14.35%	14.35%	14.35%
N2	0.02%	0.02%	0.02%
O2	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%
Total	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,360
Combustion Turbine Exhaust Emissions			
CTG Exhaust Analysis (Volume Basis - Wet)			
Ar	0.89%	0.91%	0.91%
CO2	4.98%	5.27%	5.47%
H2O	11.23%	10.26%	10.11%
N2	71.21%	72.08%	72.28%
O2	11.69%	11.48%	11.23%
SO2	0.00109%	0.00115%	0.00120%
Total	100.0%	100.0%	100.0%
NOx, ppmvd @15% O2	42.00	42.00	42.00
NOx, ppmvd @ 15% O2	42.00	42.00	42.00
NOx, ppmvd	54.85	57.46	59.56
NOx, ppmvw (wet - uncorrected exhaust gas)	48.69	51.56	53.54
NOx Massflow Added to Match CTG Manufacturer's NOx Emissions Estimate	1.00	1.00	1.00
Additonal Percent Margin included in NOx Emissions below	5%	5%	5%
NOx, lb/h as NO2	193.92	212.04	222.84
NOx, lb/MBtu (LHV)	0.18	0.18	0.18
NOx, lb/MBtu (HHV)	0.17	0.17	0.17
NOx, mg/Nm3 as NO2 (dry, 15% O2)	91.01	90.97	90.95
NOx, mg/Nm3 as NO2 (dry, 15% O2)	91.01	90.97	90.95
NOx, mg/Nm3 as NO2 (dry)	118.86	124.46	128.99
NOx, mg/Nm3 as NO2 (wet - uncorrected exhaust flow)	105.51	111.68	115.95
NOx, mg/MJ (LHV)	78.43	78.40	78.38
NOx, mg/MJ (HHV)	73.65	73.61	73.60
CO, ppmvd @ 15% O2	27.57	21.93	18.33
CO, ppmvd @ 15% O2	27.57	21.93	18.33
CO, ppmvd	36.00	30.00	26.00
CO, ppmvw (wet - uncorrected exhaust gas)	31.96	26.92	23.37
CO Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00
Additional Percent Margin included in CO Emissions below	5%	5%	5%
CO, lb/h	77.09	67.08	58.96
CO, lb/MBtu (LHV)	0.07	0.06	0.05
CO, lb/MBtu (HHV)	0.07	0.05	0.05
CO, mg/Nm3 (wet - uncorrected exhaust flow)	41.94	35.33	30.67
CO, mg/Nm3 (dry)	47.25	39.37	34.12
CO, mg/Nm3 (dry, 15% O2)	36.18	28.78	24.06
CO, mg/Nm3 (dry, 15% O2)	36.18	28.78	24.06
CO, mg/MJ (LHV)	31.18	24.80	20.74
CO, mg/MJ (HHV)	29.28	23.29	19.47
NOTE: SO2 estimate does not include the effects of SO2 oxidation			
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	9.40	9.40	9.40
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	9.40	9.40	9.40
SO2, ppmvd (with no SO2 oxidation)	12.27	12.86	13.33
SO2, ppmvw (with no SO2 oxidation)(wet - uncorrected exhaust gas)	10.90	11.54	11.98
SO2 Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0.00
Additional Percent Margin included in SO2 Emissions below	5%	5%	5%
SO2, lb/h (with no SO2 oxidation)	60.11	65.75	69.12
SO2, lb/MBtu (LHV) (with no SO2 oxidation)	0.0565	0.0565	0.0565
SO2, lb/MBtu (HHV) (with no SO2 oxidation)	0.0531	0.0531	0.0531
SO2, mg/Nm3 (wet - uncorrected exhaust flow) (with no SO2 oxidation)	32.70	34.63	35.96
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	28.21	28.21	28.21
SO2, mg/Nm3 (dry, 15% O2) (with no SO2 oxidation)	28.21	28.21	28.21
SO2, mg/Nm3 (dry) (with no SO2 oxidation)	36.84	38.59	40.01
SO2, mg/MJ (LHV) (with no SO2 oxidation)	24.31	24.31	24.31
SO2, mg/MJ (HHV) (with no SO2 oxidation)	22.83	22.83	22.83

Preparer's Initials: UZ
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Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,360
Combustion Turbine Exhaust Emissions - continued			
UHC, ppmvd @ 15% O2	6.04	5.70	5.49
UHC, ppmvd @ 15% O2	6.04	5.70	5.49
UHC, ppmvd	7.89	7.80	7.79
UHC, ppmvw (wet - uncorrected exhaust gas)	7.00	7.00	7.00
UHC Massflow Added to Match CTG Manufacturer's CO Emissions Estimate	0.00	0.00	0 00
Additional Percent Margin Included in UHC Emissions Below	5%	5%	5%
UHC, lb/h as CH4	9 67	9.99	10 11
UHC, lb/MBtu as CH4 (LHV)	0.0091	0 0086	0.0083
UHC, lb/MBtu as CH4 (HHV)	0.0085	0.0081	0.0078
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.54	4.29	4.13
UHC, mg/Nm3 as CH4 (dry, 15% O2)	4.54	4.29	4.13
UHC, mg/Nm3 as CH4 (dry)	5.93	5.86	5 85
UHC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	5.26	5 26	5.26
UHC, mg/MJ as CH4 (LHV)	3.91	3.69	3.56
UHC, mg/MJ as CH4 (HHV)	3 67	3.47	3 34
VOC percentage of UHC	50.0%	50.0%	50.0%
VOC, ppmvd @ 15% O2	3.0	2.9	2.7
VOC, ppmvd @ 15% O2	3.0	2.9	2.7
VOC, ppmvd	3 94	3.90	3 89
VOC, ppmvw (wet - uncorrected exhaust flow)	3.50	3.50	3.50
VOC Massflow Added to Match CTG Manufacturer's VOC Emissions Estimate	0.00	0.00	0 00
Additional Percent Margin Included in VOC Emissions below	5%	5%	5%
VOC, lb/h as CH4	4.84	4.99	5 06
VOC, lb/MBtu as CH4 (LHV)	0.0045	0.0043	0.0041
VOC, lb/MBtu as CH4 (HHV)	0 0043	0.0040	0.0039
VOC, mg/Nm3 as CH4 (dry, 15% O2)	2.27	2.14	2.06
VOC, mg/Nm3 as CH4 (dry, 15% O2)	2.27	2.14	2.06
VOC, mg/Nm3 as CH4 (dry)	2.96	2.93	2.93
VOC, mg/Nm3 as CH4 (wet - uncorrected exhaust flow)	2.63	2.63	2.63
VOC, mg/MJ as CH4 (LHV)	1.96	1.85	1.78
VOC, mg/MJ as CH4 (HHV)	1.84	1.73	1.67
Percent Margin included in Particulates Emissions below	5%	5%	5%
Particulates, lb/h (front half catch only)	17.85	17.85	17.85
Particulates, lb/h (front and back half catch)	35.70	35.70	35.70
Particulates, lb/MBtu (LHV) (front half catch only)	0.0168	0 0154	0 0146
Particulates, lb/MBtu (HHV) (front half catch only)	0.0158	0.0144	0 0137
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	8.38	7 66	7.29
Particulates, mg/Nm3 (dry, 15% O2) (front half catch only)	8.38	7.66	7.29
Particulates, mg/Nm3 (dry) (front half catch only)	10 94	10.48	10.33
Particulates, mg/Nm3 (wet - uncorrected exhaust flow) (front half catch only)	9.71	9.40	9.29
Particulates, mg/MJ (LHV) (front half catch only)	7.22	6 60	6 28
Particulates, mg/MJ (HHV) (front half catch only)	6.78	6.20	5.90
Percent Margin included in PM10 Emissions below	0%	0%	0%
PM10, lb/h (front half catch only)	17.00	17.00	17.00
PM10, lb/h (front and back half catch)	34 00	34.00	34 00
PM10, lb/MBtu (LHV) (front and back half catch)	0 03	0 03	0 03
PM10, lb/MBtu (HHV) (front and back half catch)	0.03	0.03	0 03
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	15 96	14.59	13.88
PM10, mg/Nm3 (dry, 15% O2) (front and back half catch)	15.96	14.59	13 88
PM10, mg/Nm3 (dry) (front and back half catch)	20 84	19.96	19.68
PM10, mg/Nm3 (wet - uncorrected exhaust flow) (front and back half catch)	18.50	17.91	17.69
PM10, mg/MJ (LHV) (front and back half catch)	13.75	12.57	11.96
PM10, mg/MJ (HHV) (front and back half catch)	12.91	11.80	11.23
CTG Wet (Total) Exhaust Gas Analysis			
Molecular Wt, lb/mol	28.26	28.40	28 44
Molecular Wt, kg/mol	12.82	12.88	12.90
Gas Constant, ft-lbf/lbm-R	54 667	54.404	54 331
Specific Volume, ft^3/lb	41.54	41.34	41.28
Specific Volume, m^3/kg	2.59	2.58	2.58
Exhaust Gas Flow, acfm	1,604,829	1,657,734	1,678,032
Specific Volume, scf/lb	13 42	13.38	13.34
Exhaust Gas Flow, scfm	518,459	535,736	542,271
Specific Volume, Nm3/kg	0.7929	0.7891	0.7880
Exhaust Gas Flow, Nm3/s	231.58	239.22	242.16

Preparer's Initials: UZ
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Project number 99262.0040

Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,360
Duct Burner Emissions			
Duct Burner Heat Input, MBtu/h (LHV) (margin included)	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (LHV) (margin included)	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (margin included)	0.0	0.0	0.0
Duct Burner Heat Input, GJ/h (HHV) (margin included)	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	0	0	0
Duct Burner Fuel LHV, Btu/lb	18,550	18,550	18,550
Duct Burner Fuel HHV, kJ/kg	43,147	43,147	43,147
Duct Burner Fuel HHV, Btu/lb	19,756	19,756	19,756
Duct Burner Fuel HHV, kJ/kg	45,952	45,952	45,952
Duct Burner Fuel Composition (Ultimate Analysis by Weight)			
Ar	0.00%	0.00%	0.00%
C	85.59%	85.59%	85.59%
H2	14.35%	14.35%	14.35%
N2	0.02%	0.02%	0.02%
O2	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%
Total	100.0%	100.0%	100.0%
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080
Duct Burner NOx, kg/kJ (HHV)	0.034	0.034	0.034
Duct Burner CO, lb/MBtu (HHV)	0.100	0.100	0.100
Duct Burner CO, kg/kJ (HHV)	0.043	0.043	0.043
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060
Duct Burner UHC, kg/kJ (HHV)	0.026	0.026	0.026
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.024	0.024	0.024
Duct Burner VOC (as CH4), kg/kJ (HHV)	0.010	0.010	0.010
Duct Burner Particulate, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010
Duct Burner Particulate, kg/kJ (HHV) (front half catch only)	0.004	0.004	0.004
Duct Burner Particulate, lb/MBtu (HHV) (front and back half catch)	0.020	0.020	0.020
Duct Burner Particulate, kg/kJ (HHV) (front and back half catch)	0.009	0.009	0.009
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.008	0.008	0.008
Duct Burner PM10, kg/kJ (HHV) (front half catch only)	0.003	0.003	0.003
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.016	0.016	0.016
Duct Burner PM10, kg/kJ (HHV) (front and back half catch)	0.007	0.007	0.007
Total SO2, lb/h from Duct Burner	0.000	0.000	0.000
Total SO2, kg/h from Duct Burner	0.000	0.000	0.000
DB NOx, lb/h	0.00	0.00	0.00
DB NOx, kg/h	0.00	0.00	0.00
DB CO, lb/h	0.00	0.00	0.00
DB CO, kg/h	0.00	0.00	0.00
DB UHC (as CH4), lb/h	0.00	0.00	0.00
DB UHC (as CH4), kg/h	0.00	0.00	0.00
DB VOC (as CH4), lb/h	0.00	0.00	0.00
DB VOC (as CH4), kg/h	0.00	0.00	0.00
DB Particulate, lb/h (front half catch only)	0.00	0.00	0.00
DB Particulate, kg/h (front half catch only)	0.00	0.00	0.00
DB Particulate, lb/h (front and back half catch)	0.00	0.00	0.00
DB Particulate, kg/h (front and back half catch)	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	0.00	0.00	0.00
DB PM10, kg/h (front half catch only)	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	0.00	0.00	0.00
DB PM10, kg/h (front and back half catch)	0.00	0.00	0.00

Preparer's Initials: UZ
10/26/00

Project number 99262.0040

Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,360
Heat Recovery Steam Generator Stack Emissions			
NOTE: Exhaust Analysis does not include the effects of post combustion control			
Stack Exhaust Analysis (Volume Basis - Wet)			
Ar	0.89%	0.91%	0.91%
CO2	4.98%	5.27%	5.47%
H2O	11.23%	10.26%	10.11%
N2	71.21%	72.08%	72.28%
O2	11.69%	11.48%	11.23%
SO2	0.00109%	0.00115%	0.00120%
Total	100.0%	100.0%	100.0%
Stack Emissions			
NOx, ppmvd @15% O2 w/o SCR	42.00	42.00	42.00
NOx, ppmvd@ user defined oxygen w/o SCR	#N/A	#N/A	#N/A
NOx, ppmvd w/o SCR	54.85	57.46	59.56
NOx, ppmvw w/o SCR	48.69	51.56	53.54
NOx, lb/h as NO2 w/o SCR	193.92	212.04	222.84
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w/o SCR	0.18	0.18	0.18
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w/o SCR	0.17	0.17	0.17
NOx, kg/h as NO2	87.96	96.18	101.08
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w/o SCR	105.51	111.68	115.95
NOx, mg/MJ (LHV) (including duct burner fuel) w/o SCR	78.43	78.40	78.38
NOx, mg/MJ (HHV) (including duct burner fuel) w/o SCR	73.65	73.61	73.60
NOx, ppmvd @15% O2 w/ SCR	15.00	15.00	15.00
NOx, ppmvd@ user defined oxygen w/ SCR	#N/A	#N/A	#N/A
NOx, ppmvd w SCR	19.59	20.52	21.27
NOx, ppmvw w SCR	17.39	18.42	19.12
NOx, lb/h as NO2 w/ SCR	65.62	71.78	75.46
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel) w SCR	0.06	0.06	0.06
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel) w SCR	0.06	0.06	0.06
NOx, kg/h as NO2	29.76	32.56	34.23
NOx, mg/Nm3 as NO2 (uncorrected exhaust flow) w SCR	35.70	37.81	39.26
NOx, mg/MJ (LHV) (including duct burner fuel) w SCR	26.54	26.54	26.54
NOx, mg/MJ (HHV) (including duct burner fuel) w SCR	24.92	24.92	24.92
SCR NH3 slip, ppmvd @15% O2	9.00	9.00	9.00
SCR NH3 slip, lb/h	14.58	15.94	16.76
CO, ppmvd @ 15% O2 w/o Catalyst	27.57	21.93	18.33
CO, ppmvd @ user defined O2 w/o Catalyst	#N/A	#N/A	#N/A
CO, ppmvd w/o Catalyst	36.00	30.00	26.00
CO, ppmvw w/o Catalyst	31.96	26.92	23.37
CO, lb/h w/o Catalyst	77.09	67.08	58.96
CO, lb/MBtu (LHV) (incl. duct burner fuel) w/o SCR	0.07	0.06	0.05
CO, lb/MBtu (HHV) (incl. duct burner fuel) w/o SCR	0.07	0.05	0.05
CO Reduction % w/ Catalyst	0%	0%	0%
CO, ppmvd @ 15% O2 w/ Catalyst	27.57	21.93	18.33
CO, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A
CO, ppmvd w/ Catalyst	36.00	30.00	26.00
CO, ppmvw w/ Catalyst	31.96	26.92	23.37
CO, lb/h w/ Catalyst	73.42	63.89	56.15
CO, lb/MBtu (LHV) (incl. duct burner fuel) w SCR	0.069	0.055	0.046
CO, lb/MBtu (HHV) (incl. duct burner fuel) w SCR	0.065	0.052	0.043
SO2, ppmvd@15% O2 (with no SO2 oxidation)	9.40	9.40	9.40
SO2, ppmvd at user defined O2 (with no SO2 oxidation)	#N/A	#N/A	#N/A
SO2, ppmvd (with no SO2 oxidation)	12.27	12.86	13.33
SO2, ppmvw (with no SO2 oxidation)	10.90	11.54	11.98
SO2, lb/h (with no SO2 oxidation)	60.11	65.75	69.12
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0565	0.0565	0.0565
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0531	0.0531	0.0531

Preparer's Initials: UZ
10/26/00 Project number 99262.0040

Case Number	21	22	23
CTG Performance Reference	GE/JEA-adjusted	GE/JEA-adjusted	GE/JEA-adjusted
CTG Model	7241FA	7241FA	7241FA
Diluent/NOx Emission Rate	DLN/42	DLN/42	DLN/42
CTG Fuel Type	Dist. Oil	Dist. Oil	Dist. Oil
CTG Load	50%	50%	50%
Ambient Temperature, F	95	59	20
HRSG Firing	Unfired	Unfired	Unfired
STG Output with two Combustion Turbine Generators in operation, kW	128,150	139,530	141,380
Heat Recovery Steam Generator Stack Emissions - continued			
NOTE: UHC calculations do NOT include the effect of any oxidation in the CO catalyst.			
UHC, ppmvd @ 15% O2	6.04	5.70	5.49
UHC, ppmvd @ user defined O2	#N/A	#N/A	#N/A
UHC, ppmvd	7.89	7.80	7.79
UHC, ppmvw	7.00	7.00	7.00
UHC, lb/h as CH4	9.67	9.99	10.11
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.009	0.009	0.008
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.009	0.008	0.008
VOC, ppmvd @ 15% O2 w/o Catalyst	3.02	2.85	2.75
VOC, ppmvd @ user defined O2 w/o CO catalyst	#N/A	#N/A	#N/A
VOC, ppmvd w/o Catalyst	3.94	3.90	3.89
VOC, ppmvw w/o Catalyst	3.50	3.50	3.50
VOC, lb/h as CH4 w/o Catalyst	4.84	4.99	5.06
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w/o CO catalyst	0.0045	0.0043	0.0041
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w/o CO catalyst	0.0043	0.0040	0.0039
VOC Reduction % w/ Catalyst	0%	0%	0%
VOC, ppmvd @ 15% O2 w/ Catalyst	3.02	2.85	2.75
VOC, ppmvd @ user defined O2 w/ Catalyst	#N/A	#N/A	#N/A
VOC, ppmvd w/ Catalyst	3.94	3.90	3.89
VOC, ppmvw w/ Catalyst	3.50	3.50	3.50
VOC, lb/h as CH4 w/ Catalyst	4.61	4.76	4.82
VOC, lb/MBtu (LHV) (incl. duct burner fuel) w CO catalyst	0.0043	0.0041	0.0039
VOC, lb/MBtu (HHV) (incl. duct burner fuel) w CO catalyst	0.0041	0.0038	0.0037
Particulate without the effect of SO2 oxidation and SCR catalysts			
Particulates, lb/h (front half catch only)	17.9	17.9	17.9
Particulates, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.0168	0.0154	0.0146
Particulates, lb/h (front and back half catch)	35.7	35.7	35.7
Particulates, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.034	0.031	0.029
PM10, lb/h (front half catch only)	17.0	17.0	17.0
PM10, lb/MBtu (incl. duct burner fuel) (front half catch only)	0.016	0.015	0.014
PM10, lb/h (front and back half catch)	34.0	34.0	34.0
PM10, lb/MBtu (incl. duct burner fuel) (front and back half catch)	0.032	0.029	0.028
Particulate including the effect of SO2 oxidation and SCR catalysts [includes 2(NH4SO4)]			
Particulates, lb/h (front half catch only)	33.3	34.7	35.6
Particulates, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.0313	0.0299	0.0291
Particulates, lb/h (front and back half catch)	51.1	52.6	53.4
Particulates, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.048	0.045	0.044
PM10, lb/h (front half catch only)	32.4	33.9	34.7
PM10, lb/MBtu (incl. duct burner fuel)(front half catch only)	0.030	0.029	0.028
PM10, lb/h (front and back half catch)	49.4	50.9	51.7
PM10, lb/MBtu (incl. duct burner fuel)(front and back half catch)	0.046	0.044	0.042
NOTE: SO2 to SO3 conversion rate (assumed), wt%	8.0%	8.0%	8.0%
SO3 conversion rate (assumed) to ammonium sulfates [2(NH4SO4)]	90.0%	90.0%	90.0%
Remaining SO2 in Exhaust Gas, lb/h	55.30	60.49	63.59
Amount of SO2 converted to SO3	4.81	5.26	5.53
Maximum Exhaust Gas ammonium sulfate [2(NH4SO4)], lb/h	15.42	16.86	17.73
Maximum H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/hr	7.36	8.05	8.47
Stack Exit Temperature, F	252	250	250
Stack Diameter, ft (estimated)	19	19	19
Stack Flow, lb/h	2,318,000	2,406,000	2,439,000
Stack Flow, scfm	518,459	535,736	542,271
Stack Flow, acfm	710,081	731,825	741,456
Stack Exit Velocity, ft/s	41.7	43.0	43.6
Selective Catalytic Reduction (SCR)			
NOx Removed, lb/h as NO2	128.3	140.3	147.4
NOx Removed, percent	66.2%	66.1%	66.1%
NH3 Slip, lb/h	14.6	15.9	16.8
Total NH3 consumption, lb/h (1:1 stoichiometric ratio, incl. slip)	62.1	67.9	71.3
Adjusted Stack Diameter (ft) estimated	18.0	18.0	18.0
Stack Exit Velocity, ft/s	46.5	47.9	48.6

Notes:

1. The emissions estimates shown in the table above are per stack.

2. The combustion turbine generator performance and emissions is based on a General Electric performance estimate provided by JEA.

3. The combustion turbine emissions estimate may include margin as indicated in the table.

Where catalysts are involved to reduce emissions, the margin applied to the CTG emissions only effects the amount of emissions removed, but not the stack emissions.

4. UHC calculations do not include the effects of any oxidation in the CO catalyst. It was assumed that the VOC/UHC ratio is 20% for natural gas firing, and 50% for distillate oil firing.

5. It was assumed that the front and back half catch of CTG particulate emissions is twice the amount of front half catch only

6. Duct Burner emissions are Black & Veatch estimates based on typical vendor data.

7. It was assumed that ammonium sulfate is measured as front half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.

8. The maximum amount of ammonium sulfates and sulfuric acid shown in the table can not occur in parallel at the same time.

Attachment 2
Potential-To-Emit (PTE) and Enveloped Spreadsheet

POTENTIAL TO EMIT EMISSION ESTIMATES FOR CRITERIA EMISSIONS

Criteria Emissions from Natural Gas Combustion Per Turbine

Pollutant	Max lb/h @59F	Hours of operation (h/yr)	Total Emission (tpy)
NO_x	23.62	8472.0	100.05
CO	52.58	8472.0	222.73
PM/PM_{10}	19.80	8472.0	83.87
SO_2	1.16	8472.0	4.91
VOC	3.49	8472.0	14.78
H2SO4	0.18	8472.0	0.76

Criteria Emissions from Fuel Oil Combustion Per Turbine

Pollutant	Max lb/h @59f	Hours of operation (h/yr)	Total Emission (tpy)
NO_x	112.41	288	16.19
CO	67.86	288	9.77
PM/PM_{10}	62.10	288	8.94
SO_2	102.97	288	14.83
VOC	7.68	288	1.11
H2SO4	12.61	288	1.82
LEAD	2.72E-03	288	3.91E-03

Combined Natural Gas and Fuel Oil for two turbines

Pollutant	Total (tpy)	No of turbines	Total Emission (tpy)
NO_x	116.24	2	232.48
CO	232.50	2	465.00
PM/PM_{10}	92.82	2	185.63
SO_2	19.74	2	39.48
VOC	15.89	2	31.78
H2SO4	2.58	2	5.16
LEAD	3.91E-03	2	0.01

Brandy Branch Hazardous Air Pollutants (HAP)

Pollutant	CC Combustion Turbines[c]-Natural Gas			CC Combustion Turbines[c]-Fuel Oil			Duct Burner[d]	
	Emission Factor lb/MMBtu	Emission rate (tons/yr)[a]		Emission Factor lb/MMBtu	Emission rate (tons/yr)[a]		Emission Factor (lb/10^6 scf)	Emission rate (tons/yr)[b]
1,3 Butadiene	4.30E-07	3.25E-03		1.60E-05	4.47E-03			
Acetaldehyde	4.00E-05	3.03E-01						
Acrolein	6.40E-06	4.84E-02						
Arsenic							2.00E-04	1.90E-05
Benzene	1.20E-05	9.08E-02		5.50E-05	1.54E-02		2.10E-03	2.00E-04
Beryllium							1.20E-05	1.14E-06
Cadmium							1.10E-03	1.05E-04
Chromium							1.40E-03	1.33E-04
Cobalt							8.40E-05	7.99E-06
Dichlorobenzene							1.20E-03	1.14E-04
Ethylbenzene	3.20E-05	2.42E-01						
Formaldehyde[e]	8.42E-05	6.37E-01		2.80E-04	7.82E-02		7.50E-02	7.13E-03
Hexane							1.80E+00	1.71E-01
Manganese							3.80E-04	3.61E-05
Mercury							2.60E-04	2.47E-05
Naphthalene	1.30E-06	9.83E-03		3.50E-05	9.77E-03		6.10E-04	5.80E-05
Nickel							2.10E-03	2.00E-04
Propylene Oxide	2.90E-05	2.19E-01						
Selenium							2.40E-05	2.28E-06
Toluene	1.30E-04	9.83E-01					3.40E-03	3.23E-04
Xylenes	6.40E-05	4.84E-01						

(a)The highest HHV was used from 59 degree Natural Gas and Fuel Oil turbine data (1785.3 MBtu/hr, 1939.3 MBtu/hr, respecitvely). The limit of operation for Natural Gas and Fuel Oil are 8472 and 288 hours per year, respectively.

(b)The highest HHV was used from 59 degree Natural Gas turbine data (22.9 MBtu/hr).

(c)AP-42 Emission Factor Table 3.1-3 for Natural Gas and Table 3.1-4 for Fuel Oil.

(d)AP-42 Emission Factor Table 1.4-3 and Table 1.4-4.

(e)AP-42 database for combustion turbine only.

Pollutant	Natural Gas[f] Emission rate (tons/yr)	Fuel Oil Emission rate (tons/yr)	Per Turbine Emission rate (tons/yr)	Total[g] Emission rate (tons/yr)
1,3 Butadiene	3.25E-03	4.47E-03	7.72E-03	1.54E-02
Acetaldehyde	3.03E-01		3.03E-01	6.05E-01
Acrolein	4.84E-02		4.84E-02	9.68E-02
Arsenic	1.90E-05		1.90E-05	3.80E-05
Benzene	9.10E-02	1.54E-02	1.06E-01	2.13E-01
Beryllium	1.14E-06		1.14E-06	2.28E-06
Cadmium	1.05E-04		1.05E-04	2.09E-04
Chromium	1.33E-04		1.33E-04	2.66E-04
Cobalt	7.99E-06		7.99E-06	1.60E-05
Dichlorobenzene	1.14E-04		1.14E-04	2.28E-04
Ethylbenzene	2.42E-01		2.42E-01	4.84E-01
Formaldehyde	6.44E-01	7.82E-02	7.22E-01	1.44E+00
Hexane	1.71E-01		1.71E-01	3.42E-01
Manganese	3.61E-05		3.61E-05	7.23E-05
Mercury	2.47E-05		2.47E-05	4.95E-05
Naphthalene	9.89E-03	9.77E-03	1.97E-02	3.93E-02
Nickel	2.00E-04		2.00E-04	3.99E-04
Propylene Oxide	2.19E-01		2.19E-01	4.39E-01
Selenium	2.28E-06		2.28E-06	4.56E-06
Toluene	9.83E-01		9.83E-01	1.97E+00
Xylenes	4.84E-01		4.84E-01	9.68E-01
Total HAP Emissions				6.61

(f)Natural gas combustion turbine and duct burner combined.

(g)Total Facility has 2 combined cycle combustion turbines.

JEA - Brandy Branch Combined Cycle Facility - Florida

Determination of Representative Emission and Stack Parameters and Potential to Emit Calculator **Rev 5a**

Combined Cycle Operation - Natural Gas

GE7FA

NOTE Ref. 10/26/00 performance data.

GE7FA

Load 100 percent

Case Name	Case1	Case2	Case3	Case4	Case5	Case6	Case7
Ambient Temp (F)	95	95	95	95	59	59	20
Evap Cooler			X	X			
Duct Firing (k)	X			X		X	
Exit Temp (F)	205	208	209	207	206	204	208
Exit Velocity (ft/s)	61.4	61.5	63.3	63.1	66.2	66.1	71.1
Emissions (lb/h)							
NO_x	22.23	21.12	21.82	22.79	23.32	23.62	24.95
CO	54.05	45.53	46.47	53.90	50.29	52.58	54.26
PM/PM_{10}	20.60	19.30	19.30	20.50	19.30	19.70	19.30
SO_2	1.09	1.03	1.07	1.11	1.14	1.16	1.22
VOC	4.77	2.73	2.80	4.58	2.95	3.49	3.15

GE7FA
Enveloped-Short Term (Load Representative) Emissions and Stack Parameters

Exit Temp (F)	204.00	368.71	K
Exit Velocity (ft/s)	61.40	18.71	m/s
Emissions (lb/h)			
NO_x	24.95	3.14	g/s
CO	54.26	6.84	g/s
PM/PM_{10}	20.60	2.60	g/s
SO_2	1.22	0.15	g/s
VOC	4.77	0.60	g/s

Load 75 percent Ref. 10/26/00 performance data.

Case Name	Case8	Case10	Case12
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	198	194	194
Exit Velocity (ft/s)	50.1	53.1	55.4
Emissions (lb/h)			
NO_x	17.34	18.89	20.01
CO	37.67	41.05	43.16
PM/PM_{10}	19.20	19.20	19.20
SO_2	0.85	0.92	0.98
VOC	2.26	2.40	2.51

Exit Temp (F)	194.00	363.15	K
Exit Velocity (ft/s)	50.10	15.27	m/s
Emissions (lb/h)			
NO_x	20.01	2.52	g/s
CO	43.16	5.44	g/s
PM/PM_{10}	19.20	2.42	g/s
SO_2	0.98	0.12	g/s
VOC	2.51	0.32	g/s

Load 50 percent Ref. 10/26/00 performance data.

Case Name	Case9	Case11	Case13
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	190	185	185
Exit Velocity (ft/s)	41.6	43.4	44.9
Emissions (lb/h)			
NO_x	13.99	15.18	15.98
CO	31.79	34.12	35.53
PM/PM_{10}	19.10	19.20	19.20
SO_2	0.68	0.74	0.78
VOC	1.90	1.99	2.06

Exit Temp (F)	185.00	358.15	K
Exit Velocity (ft/s)	41.60	12.68	m/s
Emissions (lb/h)			
NO_x	15.98	2.01	g/s
CO	35.53	4.48	g/s
PM/PM_{10}	19.20	2.42	g/s
SO_2	0.78	0.10	g/s
VOC	2.06	0.26	g/s

Distillate Oil

GE7FA

NOTE Ref. 10/26/00 performance data.

GE7FA

Load 100 percent

Case Name	Case14	Case15	Case16	Case17
Ambient Temp (F)	95	59	20	95
Evap Cooler				X
Duct Firing (k)				
Exit Temp (F)	272	265	265	274
Exit Velocity (ft/s)	69.8	75.3	79.7	71.7
Emissions (lb/h)				
NO_x	101.23	112.41	119.37	104.53
CO	61.43	67.86	72.43	62.59
PM/PM_{10}	40.80	43.40	45.00	41.60
SO_2	92.73	102.97	109.35	95.75
VOC	7.05	7.68	8.14	7.24

GE7FA
Enveloped-Short Term (Load Representative) Emissions and Stack Parameters

Exit Temp (F)	265.00	402.59	K
Exit Velocity (ft/s)	69.80	21.28	m/s
Emissions (lb/h)			
NO_x	119.37	15.04	g/s
CO	72.43	9.13	g/s
PM/PM_{10}	45.00	5.67	g/s
SO_2	109.35	13.78	g/s
VOC	8.14	1.03	g/s

Load 75 percent Ref. 10/26/00 performance data.

Case Name	Case18	Case19	Case20
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	259	255	255
Exit Velocity (ft/s)	54.8	56.9	58.9
Emissions (lb/h)			
NO_x	82.81	91.21	96.65
CO	49.21	51.94	53.79
PM/PM_{10}	36.50	38.40	39.70
SO_2	75.85	83.55	88.54
VOC	5.64	5.89	6.09

Exit Temp (F)	255.00	397.04	K
Exit Velocity (ft/s)	54.80	16.70	m/s
Emissions (lb/h)			
NO_x	96.65	12.18	g/s
CO	53.79	6.78	g/s
PM/PM_{10}	39.70	5.00	g/s
SO_2	88.54	11.16	g/s
VOC	6.09	0.77	g/s

Load 50 percent Ref. 10/26/00 performance data.

Case Name	Case21	Case22	Case23
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	252	250	250
Exit Velocity (ft/s)	46.5	47.9	48.6
Emissions (lb/h)			
NO_x	65.62	71.78	75.46
CO	77.09	67.08	58.96
PM/PM_{10}	32.40	33.90	34.70
SO_2	60.11	65.75	69.12
VOC	4.84	4.99	5.06

Exit Temp (F)	250.00	394.26	K
Exit Velocity (ft/s)	46.50	14.17	m/s
Emissions (lb/h)			
NO_x	75.46	9.51	g/s
CO	77.09	9.71	g/s
PM/PM_{10}	34.70	4.37	g/s
SO_2	69.12	8.71	g/s
VOC	5.06	0.64	g/s

JEA - Brandy Branch Combined Cycle Facility - Florida

Determination of Representative Emission and Stack Parameters and Potential to Emit Calculator

Rev 5a

Combined Cycle Operation - Natural Gas

GE7FA

NOTE Ref. 10/26/00 performance data.

GE7FA

Load 100 percent

Case Name	Case1	Case2	Case3	Case4	Case5	Case6	Case7
Ambient Temp (F)	95	95	95	95	59	59	20
Evap Cooler			X	X			
Duct Firing (k)	X			X		X	
Exit Temp (F)	205	208	209	207	206	204	208
Exit Velocity (ft/s)	61.4	61.5	63.3	63.1	66.2	66.1	71.1
Emissions (lb/h)							
NO_x	22.23	21.12	21.82	22.79	23.32	23.62	24.95
CO	54.05	45.53	46.47	53.90	50.29	52.58	54.26
PM/PM_{10}	20.60	19.30	19.30	20.50	19.30	19.70	19.30
SO_2	1.09	1.03	1.07	1.11	1.14	1.16	1.22
VOC	4.77	2.73	2.80	4.58	2.95	3.49	3.15

GE7FA
Enveloped-Short Term (Load Representative)
Emissions and Stack Parameters

Exit Temp (F)	204.00	368.71	K
Exit Velocity (ft/s)	61.40	18.71	m/s
Emissions (lb/h)			
NO_x	24.95	3.14	g/s
CO	54.26	6.84	g/s
PM/PM_{10}	20.60	2.60	g/s
SO_2	1.22	0.15	g/s
VOC	4.77	0.60	g/s

Load 75 percent Ref. 10/26/00 performance data.

Case Name	Case8	Case10	Case12
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	198	194	194
Exit Velocity (ft/s)	50.1	53.1	55.4
Emissions (lb/h)			
NO_x	17.34	18.89	20.01
CO	37.67	41.05	43.16
PM/PM_{10}	19.20	19.20	19.20
SO_2	0.85	0.92	0.98
VOC	2.26	2.40	2.51

Exit Temp (F)	194.00	363.15	K
Exit Velocity (ft/s)	50.10	15.27	m/s
Emissions (lb/h)			
NO_x	20.01	2.52	g/s
CO	43.16	5.44	g/s
PM/PM_{10}	19.20	2.42	g/s
SO_2	0.98	0.12	g/s
VOC	2.51	0.32	g/s

Load 50 percent Ref. 10/26/00 performance data.

Case Name	Case9	Case11	Case13
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	190	185	185
Exit Velocity (ft/s)	41.6	43.4	44.9
Emissions (lb/h)			
NO_x	13.99	15.18	15.98
CO	31.79	34.12	35.53
PM/PM_{10}	19.10	19.20	19.20
SO_2	0.68	0.74	0.78
VOC	1.90	1.99	2.06

Exit Temp (F)	185.00	358.15	K
Exit Velocity (ft/s)	41.60	12.68	m/s
Emissions (lb/h)			
NO_x	15.98	2.01	g/s
CO	35.53	4.48	g/s
PM/PM_{10}	19.20	2.42	g/s
SO_2	0.78	0.10	g/s
VOC	2.06	0.26	g/s

Distillate Oil

GE7FA

NOTE Ref. 10/26/00 performance data.

GE7FA

Load 100 percent

Case Name	Case14	Case15	Case16	Case17
Ambient Temp (F)	95	59	20	95
Evap Cooler				X
Duct Firing (k)				
Exit Temp (F)	272	265	265	274
Exit Velocity (ft/s)	69.8	75.3	79.7	71.7
Emissions (lb/h)				
NO_x	101.23	112.41	119.37	104.53
CO	61.43	67.86	72.43	62.59
PM/PM_{10}	40.80	43.40	45.00	41.60
SO_2	92.73	102.97	109.35	95.75
VOC	7.05	7.68	8.14	7.24

GE7FA
Enveloped-Short Term (Load Representative)
Emissions and Stack Parameters

Exit Temp (F)	265.00	402.59	K
Exit Velocity (ft/s)	69.80	21.28	m/s
Emissions (lb/h)			
NO_x	119.37	15.04	g/s
CO	72.43	9.13	g/s
PM/PM_{10}	45.00	5.67	g/s
SO_2	109.35	13.78	g/s
VOC	8.14	1.03	g/s

Load 75 percent Ref. 10/26/00 performance data.

Case Name	Case18	Case19	Case20
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	259	255	255
Exit Velocity (ft/s)	54.8	56.9	58.9
Emissions (lb/h)			
NO_x	82.81	91.21	96.65
CO	49.21	51.94	53.79
PM/PM_{10}	36.50	38.40	39.70
SO_2	75.85	83.55	88.54
VOC	5.64	5.89	6.09

Exit Temp (F)	255.00	397.04	K
Exit Velocity (ft/s)	54.80	16.70	m/s
Emissions (lb/h)			
NO_x	96.65	12.18	g/s
CO	53.79	6.78	g/s
PM/PM_{10}	39.70	5.00	g/s
SO_2	88.54	11.16	g/s
VOC	6.09	0.77	g/s

Load 50 percent Ref. 10/26/00 performance data.

Case Name	Case21	Case22	Case23
Ambient Temp (F)	95	59	20
Evap Cooler			
Duct Firing			
Exit Temp (F)	252	250	250
Exit Velocity (ft/s)	46.5	47.9	48.6
Emissions (lb/h)			
NO_x	65.62	71.78	75.46
CO	77.09	67.08	58.96
PM/PM_{10}	32.40	33.90	34.70
SO_2	60.11	65.75	69.12
VOC	4.84	4.99	5.06

Exit Temp (F)	250.00	394.26	K
Exit Velocity (ft/s)	46.50	14.17	m/s
Emissions (lb/h)			
NO_x	75.46	9.51	g/s
CO	77.09	9.71	g/s
PM/PM_{10}	34.70	4.37	g/s
SO_2	69.12	8.71	g/s
VOC	5.06	0.64	g/s

Attachment 3
BACT Tables

Table 1
NO_x BACT Clearinghouse Review List

Facility	State	Permit Date	Process	Output	Emission limit, ppmvd	Control Technology
Federal Cold Storage Cogeneration	CA	Dec-96	GE LM2500-M-2	222 MMBtu/hr	2.0	Water Injection, SCONOx
Sutter Power Plant	CA	APR-99	SW 501F	170 MW	2.5	Dry low NOx, SCR
La Paloma Generating Co.LLC	CA	MAY-99	ABB Model GT-24	262 MW	2.5	Dry-low NOx, SCR
Turlock Irrigation District	CA	AUG-94	GE LM5000	417 MMBtu/hr	3.0	SCR, Steam Injection
Sacramento Power Authority (Campbell Soup)	CA	AUG-94	Siemens V84.2	1257 MMBtu/hr	3.0	Water injection, SCR
Brooklyn Navy Yard Cogeneration Partners L.P.	NY	JUN-95	Turbine, Natural Gas Fired	240 MW	3.5	SCR
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas	170 MW	3.5	SCR
Granite Road Limited	CA	MAY-91	Turbine, Gas	460.9 MMBtu/hr	3.5	SCR, Steam Injection

Table 2 CO BACT Clearinghouse Review List						
Facility	**State**	**Permit Date**	**Process**	**Output, MW**	**Emission limit ppmvd**	**Control Technology**
Newark Bay Cogeneration Partnership, L.P.	NJ	JUN-93	Turbines, Combustion Natural Gas Fired	617	1.8 ppmvd	Oxidation Catalyst
Saranac Energy Company	NY	JUL-92	Turbines, Combustion Natural Gas Fired	1123	3 ppmvd	Oxidation Catalyst
Alabama Power, Plant Barry	AL	AUG-98	GE 7FA	170	0.057 lb/MMBtu	Good Combustion Control
Alabama Power, Plant Barry	AL	AUG-99	GE 7FA	170	0.06 lb/MMBtu	Good Combustion Control
Mobile Energy, LLC - Hog Bayou	AL	JAN-99	GE 7FA	170	0.04 lb/MMBtu	Good Combustion Control
Sutter Power Plant	CA	APR-99	Turbine, SW 501F	170	4 ppmvd	Oxidation Catalyst
Alabama Power Theodore Cogeneration Facility	AL	MAR-99	GE 7FA	170	0.086 lb/MMBtu	No Control
Blue Mountain Power, L.P	PA	JUL-96	Combustion Turbine with Heat Recovery Boiler	153	3.1 ppmvd	Oxidation Catalyst
Brooklyn Navy Yard Cogeneration Partners, L.P	NY	JUN-95	Turbine, Natural Gas Fired	240	4 ppmvd	No Control
Crockett Cogeneration (C&H Sugar)	CA	OCT-93	GE PG7221 (FA)	240	5.9 ppmvd	Good Combustion Control

Table 3 VOC BACT Clearinghouse Review List						
Facility	**State**	**Permit Date**	**Process**	**Output, MW**	**Emission limit**	**Control Technology**
Bear Mountain Limited	CA	AUG-94	Turbine, GE, Cogeneration, 48 MW	48	0.6 ppmvd	Oxidation Catalyst
Casco Ray Energy Co.	ME	JUL-98	Turbine, Combined Cycle, Natural Gas, two	170	1.0 ppmvd	Low NOx Burner
Florida Power and Light	FL	MAR-91	Turbine, Gas, 4 Each	240	1.0 ppmvd	Combustion Control
Sutter Power Plant	CA	APR-99	SW 501F, Combined Cycle	170	1.0 ppmvd	Oxidation Catalyst
Florida Power and Light	FL	JUN-91	Turbine, Gas, 4 Each	400	1.6 ppmvd	Combustion Control
Sacramento Cogeneration Authority	CA	AUG-94	GE LM6000	42	1.1 lb/hr	Oxidation Catalyst
Carson Energy Group and Central Valley Financing	CA	JUL-93	GE LM6000	42	2.46 lb/hr	Oxidation Catalyst

Attachment 4
Air Modeling Protocol and FDEP Approval

Enclosure 1

Air Dispersion Modeling Protocol

Introduction

The purpose of this enclosure is to summarize and document the mutually agreed upon air dispersion modeling protocol for the JEA Brandy Branch Combined Cycle Conversion Project, as discussed in our meeting held at the FDEP offices on September 11, 2000. As discussed in the cover letter, please review the following air dispersion modeling assumptions and methodology and provide comments and/or concurrence at your earliest convenience, but preferably no later than September 29, 2000.

Project Introduction

JEA intends to convert two of the three simple cycle combustion turbines at their Brandy Branch Facility into a combined cycle configuration. The combined cycle conversion project includes the addition of heat recovery steam generators (HRSGs) to Units 2 and 3 in a standard 2 on 1 configuration, duct burners in each HRSG, a cooling tower, and a steam turbine generator. The combined cycle conversion will be permitted to operate 8,760 hours per year at loads ranging from 50 to 100 percent. The combined cycle conversion will primarily fire natural gas, with low sulfur (0.05 percent) No.2 distillate fuel oil as back up.

The resulting steam generating capacity of the combined cycle conversion will automatically subject the Brandy Branch Facility to review and certification under the Florida Electrical Power Plant Siting Act.

Air Quality Modeling Assumptions and Methodology

Modeling Scenario:	As a major modification to an existing PSD major source, the air quality impact analysis (AQIA) will be performed only for Units 2 and 3, which are proposed to be converted into combined cycle units, and only units undergoing any modification. If the modeled predicted impacts from the combined cycle units exceed the PSD Significant Impact Levels (SILs), then Unit 1 will be included as part of the cumulative impact analysis.
Air Dispersion Model:	ISCST3 (Latest version)
Model Options:	EPA Default and Flat terrain.
GEP & Downwash:	EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash parameters for each of the combined cycle stacks.

Structures associated with the existing site, as well as the proposed additions will be included in the BPIP analysis.

Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 100 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Dispersion Coefficients:	Rural: Based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.
Meteorological Data:	Refined level modeling sequential meteorological data will consist of surface data from Jacksonville, FL and upper air data from Waycross, GA for the years 1984-1988.
Pollutants to be Modeled:	The only pollutants that are currently expected to be modeled are PM_{10}, NO_x and CO. SO_2 emissions will likely be limited to less than 40 tpy by limiting the amount of fuel oil firing.
Source Modeling Parameters:	Worst-case hourly emission rates and operating parameters will be used for short-term modeling impacts. These data will be enveloped across 50, 75 and 100 percent load cases from representative combustion turbine performance and emissions data. Potential to emit calculations and operating parameters for annual modeling impacts will be based on annual average data.
Modeled impacts:	It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. If the model predicted impacts exceed the SILs, additional agency consultation will be initiated regarding increment and cumulative air quality impact analyses.
Class I Analysis:	A regional haze visibility study and Class I SIL analysis will be performed for the Class I areas within 150 km of the proposed facility location. These areas will consist of the Okefenokee and Wolf Island Wilderness areas. For those areas within 50 km of the proposed facility location, the VISCREEN model will be used. For analysis of Class I areas beyond 50 km, the CALPUFF model will be used. The CALPUFF modeling protocol is discussed in Enclosure 2 of this submittal.
Toxics:	No toxic modeling analysis is required.

ENCLOSURE 2

BRANDY BRANCH COMBINED CYCLE CONVERSION PROJECT
CALPUFF MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

SEPTEMBER 2000

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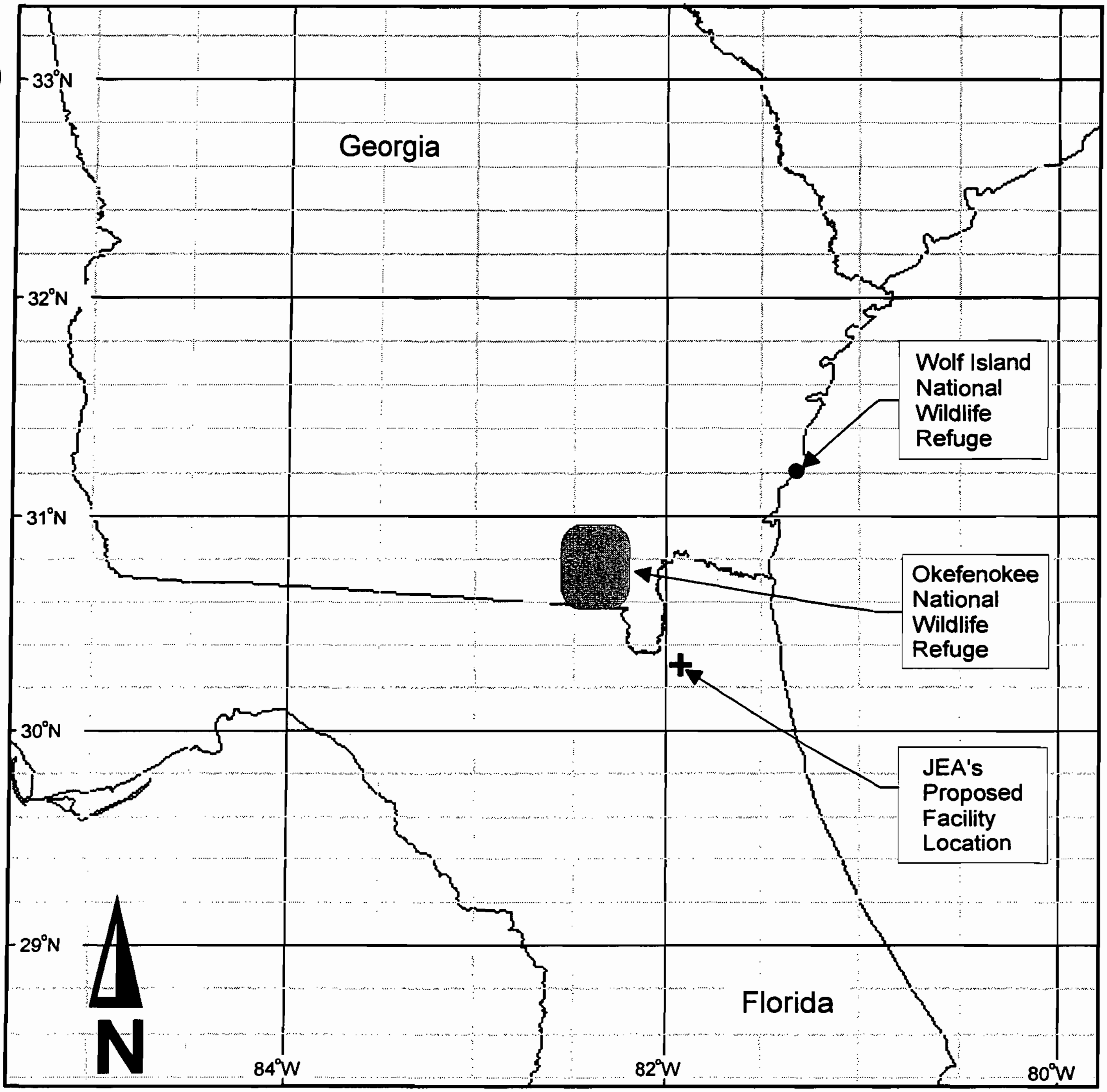
1.0 Introduction

JEA is proposing to convert two simple-cycle combustion turbines into combined-cycle combustion turbines serving one steam turbine (2x1), for a total nominal output of approximately 530 MW, at the existing Brandy Branch Facility, which is located near the city of Baldwin in northeastern Florida. As part of the air impact evaluation for the proposed facility, the Florida Department of Environmental Projection (FDEP) has requested that analyses of the proposed facility's affect on the Okefenokee National Wildlife Refuge (ONWR) and Wolf Island National Wildlife Refuge (WINWR) be performed. The ONWR and WINWR are Prevention of Significant Deterioration (PSD) Class I areas located in southeastern Georgia approximately 34 km north-northwest and 127 km north-northeast, respectively, of the proposed facility site. 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, deposition, and Class I Significant Impact Levels (SILs). Figure 1-1 presents the locations of the proposed project site with respect to the ONWR and WINWR.

The CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Draft Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) dated October 1999, as well as coordination with the FDEP who will in turn communicate as necessary with the U.S. Fish and Wildlife Service (FWS) which is the Federal Land Manager (FLM) for both areas. 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.



Location of Brandy Branch Facility
with Respect to
Okefenokee and Wolf Island
National Wildlife Refuges

Figure 1-1

Site wrt Class I areas.srf

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, version 5.4) air modeling system will be used to model the emissions associated with the two combined-cycle combustion turbines at the proposed facility and assess the AQRVs at ONWR and WINWR. 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 model will first be used in a screening mode called CALPUFF 'Lite' to determine impacts onto the Class I areas. This method simplifies the modeling process while introducing a high level of conservatism. If the 'Lite' results are below the required thresholds of the previously listed AQRVs, the demonstration will be considered complete and a refined CALPUFF analysis will not be pursued. CALPUFF 'Lite' bypasses the need for the intensive meteorological processor, CALMET. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. Simply, CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. If a refined analysis is necessary, the processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts. Both CALMET and CALPUFF (including the 'Lite' and refined methodology) will be used in a manner that is recommended by the IWAQM Phase 2 Report and Draft Phase I FLAG Report.

2.2 CALPUFF Model Settings

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

2.3 Building Wake Effects

Both the screening and refined (if necessary) CALPUFF analyses will include the proposed facility's building dimensions to account for the effects of building-induced

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	<u>CALPUFF 'Lite' – screening mode</u> 5 years of Jacksonville data (including precipitation) processed to include such parameters as the surface roughness, Bowen ratio, albedo, etc. <u>CALPUFF – refined mode</u> CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour SO_4, NO_3 and PM_{10} concentrations for the year. <u>Deposition:</u> Highest predicted annual, SO_4 and NO_3 values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Ozone: 80 ppb; Ammonia: 10 ppb

downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

2.4 Receptor Locations

The CALPUFF 'Lite' analysis will use rings of discrete Cartesian receptors located at distances equal to that of the closest and furthest boundaries of the Class I areas to the proposed project location. Specifically, the rings will consist of receptor spacing of every 1-degree beginning at the appropriate distances from the proposed facility location.

The refined CALPUFF analysis, if necessary, will use an array of discrete receptors at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the ONWR and WINWR. The same modeling grid as was used in the simple cycle project will again be used here. Specifically, the array will consist of receptor spacing of 2 km within the Class I areas beginning at a distance of 50 km from the proposed facility location and continuing to the farthest extent of the ONWR and WINWR.

2.5 Meteorological Data Processing

The meteorological data that will be used in the CALPUFF screening modeling will consist of 5 years of surface observations (1984-1988) for Jacksonville, Florida extracted from the National Climatic Data Center's (NCDC) Solar and Meteorological Surface Observational Network (SAMSON) CD-ROM set. These five years will be combined with upper air, twice-daily mixing height data from Waycross, Georgia downloaded from the SCRAM BBS for the same five-year period. The data set will be processed with PCRammet for wet deposition to give CALPUFF enough information to perform the Mesopuff II chemistry transformations. This processing allows CALPUFF to run in screening mode by providing extended meteorological variables such as surface friction, surface roughness, albedo, Bowen ratio, precipitation, etc. used in the atmospheric plume dispersion.

If the refined CALPUFF analysis is employed, the California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.2) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

The CALMET settings, including horizontal and vertical grid coverage, number of weather stations (surface, upper air, and precipitation), and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed facility to the receptors at the ONWR and WINWR with at least a 50-km buffer zone in each direction. The air modeling analysis will be performed in the UTM coordinate system.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets, prognostic wind fields or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for a one-year data base set; specifically, 1990. The analysis will use the MM4 mesoscale meteorological data set to initialize the CALMET wind field. The data will be extracted from a 12-volume CD-ROM set distributed by the National Climatic Data Center (NCDC). The MM4 data have a horizontal spacing or resolution of 80 km and are used to simulate atmospheric variables within the modeling domain.

The mesoscale meteorological data set (MM4) to be used in CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables will be processed into the appropriate format and introduced into the CALMET model through the utilization of additional data files obtained from numerous sources. These ancillary data files are described in more detail in the following sections.

2.5.4 Surface Data Stations and Processing

The surface station data for the CALPUFF analyses will consist of data from several National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The station data may be obtained directly from NCDC or extracted from a CD-ROM set put out by NCDC. The data will be processed with the CALMET preprocessor utility program, SMERGE, to create one surface file.

2.5.5 Upper Air Data Stations and Processing

The analysis will include several upper air NWS stations located within the CALMET domain. Data for these stations will be obtained from the NCDC Radiosonde Data CD and processed into the NCDC Tape Deck (TD) 6201 format by the READ62 utility program for input to CALMET.

2.5.6 Precipitation Data Stations and Processing

Precipitation data will be processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation recording stations within the CALMET domain. The precipitation files are contained in a 2-volume CD-ROM set from NCDC. The utility programs PXTRACT and PMERGE will be used to process the data into the format for the Precip.dat file that is used by CALMET.

2.5.7 Geophysical Data Processing

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

2.6 Facility Emissions

Performance data for the combustion turbines will be based on vendor data at certain design ambient temperatures at base load operation, considering both natural gas and distillate fuel oil firing. The maximum pound per hour emission rates considering representative ambient temperatures at base load operation for natural gas and distillate fuel oil firing will be used for the pollutants modeled with CALPUFF.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system (either screening or refined mode) will be used to complete the Class I analyses on the ONWR and WINWR, including regional haze, deposition (both sulfur and nitrogen), and Class I SILs. The following analyses will be performed as described regardless of the modeling methodology (i.e., screening or refined modeling).

3.1 Regional Haze Analysis

Regional haze analyses 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.

3.1.1 Visibility

Visibility is an AQRV for both the ONWR and WINWR. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because either all or portions of the Class I areas lie beyond 50 km from the proposed facility, the change in visibility will be analyzed as regional haze at those locations. 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:

$$bext(Mm-1) = 3912 / vr(Mm-1)$$

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 change in b_{extb}, or; percent change in extinction. Based on the IWAQM Phase II 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:

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

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile air quality days. The background visual ranges for the ONWR and WINWR will be obtained from the Draft Phase I FLAG document. The average relative humidity factor for each species' worst day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the maximum impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Draft Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). Again, all of this can be accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis (both screening and refined) will follow the recommendations contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, (EPA, 12/98). Table 3-1 summarizes the IWAQM Phase II recommendations. The methodology below 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 six modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. A typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain maximum 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

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

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

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

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

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

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

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

   in terms of deciviews:

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

   in terms of percent change of visibility:

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

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed facility'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.

Table 3-1

Outline of IWAQM Refined Modeling Analyses Recommendations*

Meteorology	CALPUFF 'Lite' 5 years of the closest surface station and upper air station. Refined CALPUFF 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 sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	CALPUFF 'Lite' Rings of receptors spaced every 1-degree. Refined CALPUFF Within Class I area(s) of concern.
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, NO_3, and PM_{10} values; compute a day-average relative humidity factor (*f*(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction. This can all now be accomplished with the use of the CALPOST post-processor.

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

3.2 Deposition Analyses

Deposition analyses will be performed for the ONWR and WINWR for both sulfates and nitrates. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report. 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. Perform individual CALPOST post-processor runs to output the maximum annual average wet and dry deposition impacts of SO_4 and NO_3 in $g/m^2/s$ units.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the above CALPOST runs to account for normalization based on the ratio of molecular weights, as well as the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results will be in kg/ha/yr.
4. For sulfate deposition, sum the results of both the wet deposition and dry deposition values for the SO_4 CALPOST runs.
5. For nitrate deposition, sum the results of both the wet deposition and dry deposition values for the NO_3 CALPOST runs.

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto to the ONWR and WINWR will be calculated for the criteria pollutants that exceed PSD Significant Emission Levels (SELs) 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.

Gujjarlapudi, Ebenezer S.

From: Chris Carlson TAL 850/921-9537 [Chris.Carlson@dep.state.fl.us]
Sent: Friday, September 22, 2000 2:00 PM
To: Gujjarlapudi, Ebenezer S.
Cc: Mike Halpin
Subject: JEA Brandy Branch Modeling Protocols

Dear Ebensezer,

I am sending this e-mail to inform you that I have reviewed the two modeling protocols that Black & Veatch submitted for the JEA Brandy Branch Project. As a result of our phone conversation earlier today, I no longer have any questions about the protocols and this e-mail will serve as the Department's approval of the two protocols. If you have any further questions, please contact me.

Sincerely,
Chris Carlson
Meteorologist
Florida Dept. of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
MS # 5505
Tallahassee, FL 32399-2400
phone: (850)921-9537
fax: (850)922-6979
Chris.Carlson@dep.state.fl.us

Attachment 5
Air Modeling Results

Attachment 6
VISCREEN

Visual Effects Screening Analysis for
Source: Brandy Branch Combined C
Class I Area: Okefenokee

*** Level-1 Screening ***

Input Emissions for

Particulates	90.00	LB /HR
NOx (as NO2)	238.74	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	34.00 km
Min. Source-Class I Distance:	34.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	135.	43.3	34.	2.00	5.106*	.05	.035
SKY	140.	135.	43.3	34.	2.00	1.875	.05	-.046
TERRAIN	10.	84.	34.0	84.	2.00	4.538*	.05	.050
TERRAIN	140.	84.	34.0	84.	2.00	.740	.05	.022

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	9.044*	.05	.111*
SKY	140.	0.	1.0	168.	2.00	1.687	.05	-.067*
TERRAIN	10.	0.	1.0	168.	2.00	10.283*	.05	.113*
TERRAIN	140.	0.	1.0	168.	2.00	3.253*	.05	.109*

Visual Effects Screening Analysis for
Source: Brandy Branch Combined C
Class I Area: Okefenokee

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	90.00	LB /HR
NOx (as NO2)	238.74	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	9
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	34.00 km
Min. Source-Class I Distance:	34.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability: 4	
Wind Speed: 3.53 m/s	

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	140.	45.4	29.	2.08	.321	.05	-.001
SKY	140.	140.	45.4	29.	2.00	.130	.05	-.002
TERRAIN	10.	84.	34.0	84.	2.87	.098	.06	.001
TERRAIN	140.	84.	34.0	84.	2.00	.043	.06	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	15.	19.9	154.	2.00	.477	.05	-.002
SKY	140.	15.	19.9	154.	2.00	.193	.05	-.003
TERRAIN	10.	0.	1.0	168.	2.00	.512	.05	.008
TERRAIN	140.	0.	1.0	168.	2.00	.178	.05	.007

Attachment 7
CALPUFF

Regional Haze Analysis - CALPUFF - Lite 11/10/2000 15:17

Location: Okefenokee National Wildlife Refuge

Background extinction:[1] 60.20 Mm-1 Background Visual Range: 65 km

SO4 Maximum Impact Day 1987/357 Avg. f(RH)[2] = 5.7

SO4

Impact(ug/m3)	Receptor #	x	y
6.48E-02	173	414.837	3304.904

NO3

Impact(ug/m3)	Receptor #	x	y
1.19E-01	175	413.101	3304.721

PM10

Impact(ug/m3)	Receptor #	x	y
1.41E-01	237	366.81	3327.299

Background Extinction of the Source: 4.29 Mm-1

Percent Change in Extinction: 7.13 %

NO3 Maximum Impact Day 1987/357 Avg. f(RH)[2] = 5.7

SO4

Impact(ug/m3)	Receptor #	x	y
6.48E-02	173	414.837	3304.904

NO3

Impact(ug/m3)	Receptor #	x	y
1.19E-01	175	413.101	3304.721

PM10

Impact(ug/m3)	Receptor #	x	y
1.41E-01	237	366.81	3327.299

Background Extinction of the Source: 4.29 Mm-1

Percent Change in Extinction: 7.13 %

PM10 Maximum Impact Day 1985/333 Avg. f(RH)[2] = 6.0

SO4

Impact(ug/m3)	Receptor #	x	y
9.55E-03	737	437.211	3447.675

NO3

Impact(ug/m3)	Receptor #	x	y
3.76E-02	1079	407.044	3451.916

PM10

Impact(ug/m3)	Receptor #	x	y
2.38E-01	359	407.871	3404.523

Background Extinction of the Source: 1.35 Mm-1

Percent Change in Extinction: 2.24 %

[1]Values from Bud Rolefson of the FWS.
[2]Average relative humidity factor for that day.

Regional Haze Analysis - CALPUFF - Lite 11/10/2000 15:17

Location: Wolf Island National Wild Life Refuge

Background extinction:[1] 60.20 Mm-1 Background Visual Range: 65 km

SO4 Maximum Impact Day 1987/357 Avg. f(RH)[2] = 5.1

SO4

Impact(ug/m3)	Receptor #	x	y
3.60E-02	133	503.381	3266.28

NO3

Impact(ug/m3)	Receptor #	x	y
3.35E-02	167	437.852	3328.447

PM10

Impact(ug/m3)	Receptor #	x	y
6.71E-02	166	440.048	3228.975

Background Extinction of the Source: 1.49 Mm-1

Percent Change in Extinction: 2.47 %

NO3 Maximum Impact Day 1987/357 Avg. f(RH)[2] = 3.4

SO4

Impact(ug/m3)	Receptor #	x	y
5.80E-03	231	308.181	3273.097

NO3

Impact(ug/m3)	Receptor #	x	y
9.01E-02	221	323.85	3256.871

PM10

Impact(ug/m3)	Receptor #	x	y
3.35E-02	221	323.85	3256.871

Background Extinction of the Source: 1.30 Mm-1

Percent Change in Extinction: 2.16 %

PM10 Maximum Impact Day 1985/333 Avg. f(RH)[2] = 4.9

SO4

Impact(ug/m3)	Receptor #	x	y
1.47E-02	302	299.006	3423.102

NO3

Impact(ug/m3)	Receptor #	x	y
1.66E-02	290	287.147	3398.788

PM10

Impact(ug/m3)	Receptor #	x	y
1.25E-01	73	532.489	3392.364

Background Extinction of the Source: 0.74 Mm-1

Percent Change in Extinction: 1.22 %

[1]Values from Bud Rolefson of the FWS.
[2]Average relative humidity factor for that day.

JEA
Brandy Branch Generating Station

Construction Permit Application

December 2000

BLACK & VEATCH

Contents

Attachments

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: JEA	
2. Site Name: Brandy Branch Generating Station	
3. Facility Identification Number: 0310485 [ ] Unknown	
4. Facility Location: JEA Brandy Branch Facility Street Address or Other Locator: City: Baldwin City County: Duval Zip Code: 32234	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: Name : N. Bert Gianazza, P.E. Title : Environmental Permitting and Compliance
2. Application Contact Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
3. Application Contact Telephone Numbers: Telephone: (904) 665 - 6247 Fax: (904) 665 - 7376

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	12-8-00
2. Permit Number:	0310485-003-AC
3. PSD Number (if applicable):	PSD-FL-310
4. Siting Number (if applicable):	PA 00-43

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:________________________

Operation permit number to be revised:________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:________________________

Reason for revision:________________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Walter P. Bussells, Managing Director and CEO
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (904) 665-7220 Fax: (904) 665-7366
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [x], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.* 11/30/00 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: Charles J. Schutty Registration Number: 43646
2.	Professional Engineer Mailing Address: Organization/Firm: Black & Veatch Corporation Street Address 8400 Ward Parkway City: State:Zip Code: Kansas City, MO 64114
3.	Professional Engineer Telephone Numbers: Telephone: (913) 458 - 2369 Fax: (913) 458 - 2934

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X], 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.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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.

Charles J. Schutty
Signature

December 8, 2000
Date

(seal)

CHARLES J. SCHUTTY
CERTIFICATE
No. 43646
FLORIDA
REGISTERED ENGINEER

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
002	Unit 2 – 170 MW Combined Cycle Combustion turbine with supplemental firing	AC1A	N/A
003	Unit 3 – 170 MW Combined Cycle Combustion turbine with supplemental firing	AC1A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $__________________ [x] Not Applicable *(Part of the Site Certification Fee)*

Construction/Modification Information

1. Description of Proposed Project or Alterations:

See also project description in SCA Appendix 10.7

The Brandy Branch facility consists of three simple cycle combustion turbines permitted to operate for 4,750 hours per year. The proposed project, also known as the "Brandy Branch Generating Station", consists of the conversion of two (Units 2 and 3) of the three already permitted simple cycle combustion turbine units into a two-on-one combined cycle configuration. The conversion involves the addition of two heat recovery steam generators (HRSGs), one per turbine, connected to a single steam turbine.

2. Projected or Actual Date of Commencement of Construction:	2Q, 2003
3. Projected Date of Completion of Construction:	2Q, 2004

Application Comment

This permit is for the construction/modification of two combustion turbines (emission unit IDs 002 and 003) from simple to combined cycle.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17	East (km): 408.81	North (km): 3354.38	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 30 19 14		Longitude (DD/MM/SS): 81 56 55	
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: N. Bert Gianazza, P.E. Environmental Permitting and Compliance.
2. Facility Contact Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City : Jacksonville State: FL Zip Code: 32202-3139
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6247 Fax: (904) 665-7376

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Attachment A for Facility Applicable regulations.

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	A				
CO	A				
VOC	B				
SO2	B		39.5	ESCPSD	288 hrs of operation on fuel oil per emission unit (units 2 and 3)
PM	A				
PM10	A				
PB	B				
HAPS	B				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: SCA Section 4 [ ] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [X] Attached, Document ID: SCA Appendix 10.7 [ ] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:________________________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________[X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________[X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION

(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unit 2 – 170 MW Combined Cycle Combustion Turbine with supplemental firing (40 CFR Subpart Dc duct burners).

4. Emissions Unit Identification Number: [ ] No ID
ID: 002 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)
The 170 MW combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine.
Natural gas is the primary fuel; low sulfur distillate fuel oil is the back-up fuel.

Applicant requests the following permit condition:
Excess emissions resulting form startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emission shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle plant operation. During start-up to simple cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Dry Low NO_x (DLN) Combustor. Water injection during fuel oil firing. Selective Catalytic Reduction (SCR).	
2. Control Device or Method Code(s): 024, 028, 065	

Emissions Unit Details

1. Package Unit: Combined cycle combustion turbine generator Manufacturer: General Electric	Model Number: PG 7241 FA
2. Generator Nameplate Rating: 170 MW	
3. Incinerator Information: N/A Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural gas firing) (Fuel oil firing)	1,910.2 (HHV) 2,059.4 (HHV)	MMBtu/hr MMBtu/hr
2. Maximum Incineration Rate:	N/A	lb/hr	tons/day
3. Maximum Process or Throughput Rate: N/A			
4. Maximum Production Rate: N/A			
5. Requested Maximum Operating Schedule:			
For Natural Gas:	24 hours/day		7 days/week
	52 weeks/year		8760 hours/year
For Fuel Oil:	24 hours/day		7 days/week
	12 days/year		288 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum Heat Input Rate in Field 1 is based on and includes supplementary firing for natural gas firing, (Higher heating value (HHV)) Maximum heat Input Rate during No.2 oil firing is 2059.4 mmBtu/hr (HHV) *Maximum hours of operation on natural gas are 8,760 hr/yr and 288 hr/yr for No.2 Fuel oil.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A- General Provisions	Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.
40 CFR 60, Subpart Dc- Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	
40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines	
40 CFR 72, Permits Regulation	
40 CFR 73, Sulfur Dioxide Allowance System	
40 CFR 75, Continuos Emission Monitoring	
62-204.800(7)(b), Federal Regulations Adopted by Reference- Standards of Performance for New Stationary Sources	
62-297.520, Stationary Sources- Emissions Monitoring	
Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control	
Jacksonville Environmental Protection Board (JEPB), Rule 2 Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited	
Ordinance Code, City of Jacksonville (JOC), Title V, Chapter 362, Air and Water Pollution	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? ID #23 on Plot Plan in Attachment C		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): One 190-foot vertical cylindrical exhaust stack associated with the CT/HRSG		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 190 feet	7. Exit Diameter: 18 feet
8. Exit Temperature: 210 °F	9. Actual Volumetric Flow Rate: 1,011,200 acfm	10. Water Vapor: N/A
11. Maximum Dry Standard Flow Rate: N/A		12. Nonstack Emission Point Height: N/A
13. Emission Point UTM Coordinates: Zone: 17 East (km): 408.774 North (km): 3354.531		
14. Emission Point Comment (limit to 200 characters):		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment _1____ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e., 8,760 hours)		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 1.87	5. Maximum Annual Rate: 16,405.25	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur:	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1020
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 1910.2 mmBtu/hr / 1020 mmBtu/mmscf = 1.87 mmscf/hr Maximum Annual Rate = 8760 hrs/yr x 1910.2 mmBtu/hr / 1020 mmBtu/mmscsf = 16,405.25 mmscf/hr		

Segment Description and Rate: Segment _2____ of ___2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Combustion turbine operating in combined cycle on No. 2 distillate fuel oil. Unit 2 will operate on No.2 distillate fuel oil for 288 hours per year.		
9. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate: 14.82	5. Maximum Annual Rate: 4,266.96	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.05	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 139
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 2059.4 mmBtu/hr / 139 mmBtu/thousand gallons = 14.82 thousand gallons/hr Maximum Annual Rate = 288 hrs/yr x 2059.4 mmBtu/hr / 139 mmBtu/thousand gallons = 4,266.96 thousand gallons/yr		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	065	024, 028	EL
CO			EL
VOC			EL
SO2			EL
PM			EL
PM10			EL
PB			EL
HAPS			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control: 61%
3. Potential Emissions: Natural Gas Firing 24.95 lb/hour 109.28 tons/year Fuel Oil Firing 119.37 lb/hour 17.19 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 24.95 lb/hr * 8760 hr/yr * 1/2000 lb = 109.28 tons per year Fuel Oil Firing: 119.37 lb/hr * 288 hr/yr* 1/ 2000 lb = 17.19 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of __3____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 3.5 ppm (at 15% O_2 for Natural Gas)	4. Equivalent Allowable Emissions: 24.95 lb/hour 109.28 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing. OTHER Explanation : BACT	

Allowable Emissions Allowable Emissions _2____ of __3____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 15 ppm (at 15% O_2) for Fuel Oil	4. Equivalent Allowable Emissions: 119.37 lb/hour 17.19 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of fuel oil firing. OTHER Explanation : BACT.	

Allowable Emissions Allowable Emissions _3____ of __3____

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 75 ppm (at 15% O_2) for Natural Gas	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 54.26 lb/hour 237.66 tons/year Fuel Oil Firing 72.43 lb/hour 10.43 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 54.26 lb/hr * 8760 hr/yr * 1/2000 lb = 237.66 tons per year Fuel Oil Firing: 72.43 lb/hr * 288 hr/yr* 1/ 2000 lb = 10.43 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 54.26 lb/hour	4. Equivalent Allowable Emissions: 54.26 lb/hour 237.66 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing. OTHER Explanation : BACT.	

Allowable Emissions Allowable Emissions _2___ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 72.43 lb/hour	4. Equivalent Allowable Emissions: 72.43 lb/hour 10.43 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of Fuel oil firing. OTHER Explanation : BACT.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units – Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing 20.60 lb/hour 90.23 tons/year Fuel Oil Firing 62.10 lb/hour 8.94 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 20.60 lb/hr * 8760 hr/yr * 1/2000 lb = 90.23 tons per year Fuel Oil Firing: 62.10 lb/hr * 288 hr/yr* 1/ 2000 lb = 8.94 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of __1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule. - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 1.22 lb/hour 5.34 tons/year Fuel Oil Firing 109.35 lb/hour 15.74 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
10. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 1.22 lb/hr * 8760 hr/yr * 1/2000 lb = 5.34 tons per year Fuel Oil Firing: 109.35 lb/hr * 288 hr/yr* 1/ 2000 lb = 15.74 tons per year	
11. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.22 lb/hour	4. Equivalent Allowable Emissions: 1.22 lb/hour 5.34 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

Allowable Emissions Allowable Emissions _2____ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 109.35 lb/hour	4. Equivalent Allowable Emissions: 109.35 lb/hour 15.74 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of Fuel oil firing.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 4.77 lb/hour 20.89 tons/year Fuel Oil Firing 8.14 lb/hour 1.17 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
12. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 4.77 lb/hr * 8760 hr/yr * 1/2000 lb = 20.89 tons per year Fuel Oil Firing: 8.14 lb/hr * 288 hr/yr* 1/ 2000 lb = 1.17 tons per year	
13. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 4.77 lb/hour	4. Equivalent Allowable Emissions: 4.77 lb/hour 20.89 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

Allowable Emissions Allowable Emissions _2____ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.14 lb/hour	4. Equivalent Allowable Emissions: 8.14 lb/hour 1.17 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of Fuel oil firing.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __1__

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM_{10} pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters): Florida Air Regulation: Rule 62.296	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ___1__ of ___6_

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor ___2__ of ___6_

1. Parameter Code: WTF	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Rule: New Source Performance Standards 40 CFR 60, Subpart GG	

<u>Continuous Monitoring System:</u> Continuous Monitor ___3__ of ___6_

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR Part 75.	

<u>Continuous Monitoring System:</u> Continuous Monitor ___4__ of ___6_

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement: Later	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number:Later	Serial Number: Later
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Natural Gas flow monitor installed pursuant to 40 CFR 75.	

Continuous Monitoring System: Continuous Monitor ___5__ of ___6_

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number: Later
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. This CMS will be installed on the HRSG stack. Required by 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor ___6__ of ___6_

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number: Later
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS for Opacity will be installed before operation of the emission source. This CMS will be installed on the HRSG stack. Required by 40 CFR Part 75.	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment E [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: SCA BACT Analysis Appendix 10.7, Section 3.0
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment F [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date: [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:__________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: SCA PSD Application Appendix 10.7 [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment: None

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:__________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [x] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: Attachment G

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION

(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

4. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Unit 3 – 170 MW Combined Cycle Combustion Turbine with supplemental firing.

4. Emissions Unit Identification Number: ID: 003 — [ ] No ID [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)
The 170 MW combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine.
Natural gas is the primary fuel; low sulfur distillate fuel oil is the back-up fuel.

Applicant requested emission limitation:
Excess emissions resulting form startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emission shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle plant operation. During start-up to simple cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.

Emissions Unit Control Equipment

2. Control Equipment/Method Description (Limit to 200 characters per device or method): Dry Low NO_x (DLN) Combustor. Water injection during fuel oil firing. Selective Catalytic Reduction (SCR).
2. Control Device or Method Code(s): 024, 028, 065

Emissions Unit Details

1. Package Unit: Combined cycle combustion turbine generator Manufacturer: General Electric	Model Number: 7FA
2. Generator Nameplate Rating:	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	(Natural gas firing) (Fuel oil firing)		1,910.2 (HHV) 2,059.4 (HHV)	mmBtu/hr mmBtu/hr
2. Maximum Incineration Rate:	N/A	lb/hr		tons/day
3. Maximum Process or Throughput Rate: N/A				
4. Maximum Production Rate: N/A				
5. Requested Maximum Operating Schedule:				
For Natural Gas:	24 hours/day			7 days/week
	52 weeks/year			8760 hours/year
For Fuel Oil:	24 hours/day			7 days/week
	12 days/year			288 hours/year
7. Operating Capacity/Schedule Comment (limit to 200 characters):				

Maximum Heat Input Rate in Field 1 is based on and includes supplementary firing for natural gas firing, (Higher heating value (HHV))

Maximum heat Input Rate during No.2 oil firing is 2059.4 mmBtu/hr (HHV)

*Maximum hours of operation on natural gas are 8,760 hr/yr and 288 hr/yr for No.2 Fuel oil.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A- General Provisions	Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.
40 CFR 60, Subpart Dc-	
40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines	
40 CFR 72, Permits Regulation	
40 CFR 73, Sulfur Dioxide Allowance System	
40 CFR 75, Continuos Emission Monitoring	
62-204.800(7)(b), Federal Regulations Adopted by Reference- Standards of Performance for New Stationary Sources	
62-297.520, Station Sources- Emissions Monitoring	
Ordinance Code, City of Jacksonville (JOC), Title X, Chapter 376, Odor Control	
Jacksonville Environmental Protection Board (JEPB), Rule 2 Part IX, General Pollutant Emission Limiting Standards – Objectionable Odor Prohibited	
Ordinance Code, City of Jacksonville (JOC), Title V, Chapter 362, Air and Water Pollution	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

4. Identification of Point on Plot Plan or Flow Diagram? ID #23 on Plot Plan in Attachment 2	6. Emission Point Type Code: 1

7. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): One 190-foot vertical cylindrical exhaust stack associated with the combustion turbine
8. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A

9. Discharge Type Code: V	6. Stack Height: 190 feet	7. Exit Diameter: 18 feet
8. Exit Temperature: 210 °F	9. Actual Volumetric Flow Rate: 1,011,200 acfm	10. Water Vapor: N/A

11. Maximum Dry Standard Flow Rate: N/A	12. Nonstack Emission Point Height: N/A

13. Emission Point UTM Coordinates:		
Zone:17	East (km):408.713	North (km):3354.531

14. Emission Point Comment (limit to 200 characters):

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment _1____ of __2___

2. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Combustion turbine operating in combined cycle on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e., 8,760 hours)

2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 1.87	5. Maximum Annual Rate: 16,405.25	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur:	10. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1020

11. Segment Comment (limit to 200 characters):

$$\text{Maximum Hourly Rate} = \frac{1910.2 \text{ mmBtu/hr}}{1020 \text{ mmBtu/mmscf}} = 1.87 \text{ mmscf/hr}$$

$$\text{Maximum Annual Rate} = \frac{8760 \text{ hrs/yr} \times 1910.2 \text{ mmBtu/hr}}{1020 \text{ mmBtu/mmscsf}} = 16{,}405.25 \text{ mmscf/hr}$$

Segment Description and Rate: Segment _2____ of ___2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Combustion turbine operating in combined cycle on No. 2 distillate fuel oil. Unit 2 will operate on No.2 distillate fuel oil for 288 hours per year.

11. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate: 14.82	5. Maximum Annual Rate: 4,266.96	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.05	10. Maximum % Ash: N/A	11. Million Btu per SCC Unit: 139

11. Segment Comment (limit to 200 characters):

$$\text{Maximum Hourly Rate} = \frac{2059.4 \text{ mmBtu/hr}}{139 \text{ mmBtu/thousand gallons}} = 14.82 \text{ thousand gallons/hr}$$

$$\text{Maximum Annual Rate} = \frac{288 \text{ hrs/yr} \times 2059.4 \text{ mmBtu/hr}}{139 \text{ mmBtu/thousand gallons}} = 4{,}266.96 \text{ thousand gallons/yr}$$

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	065	024, 028	EL
CO			EL
VOC			EL
SO2			EL
PM			EL
PM10			EL
PB			EL
HAPS			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control: 61%
3. Potential Emissions: Natural Gas Firing 24.95 lb/hour 109.28 tons/year Fuel Oil Firing 119.37 lb/hour 17.19 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
10. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 24.95 lb/hr * 8760 hr/yr * 1/2000 lb = 109.28 tons per year Fuel Oil Firing: 119.37 lb/hr * 288 hr/yr* 1/ 2000 lb = 17.19 tons per year	
11. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of __3____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
5. Requested Allowable Emissions and Units: 3.5 ppm (at 15% O_2 for Natural Gas)	4. Equivalent Allowable Emissions: 24.95 lb/hour 109.28 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing. OTHER Explanation : BACT	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 15 ppm (at 15% O_2) for Fuel Oil	4. Equivalent Allowable Emissions: 119.37 lb/hour 17.19 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of fuel oil firing. OTHER Explanation : BACT.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 75 ppm (at 15% O_2) for Natural Gas	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing - CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 54.26 lb/hour 237.66 tons/year Fuel Oil Firing 72.43 lb/hour 10.43 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
14. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 54.26 lb/hr * 8760 hr/yr * 1/2000 lb = 237.66 tons per year Fuel Oil Firing: 72.43 lb/hr * 288 hr/yr* 1/ 2000 lb = 10.43 tons per year	
15. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 54.26 lb/hour	4. Equivalent Allowable Emissions: 54.26 lb/hour 237.66 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing. OTHER Explanation : BACT.	

Allowable Emissions Allowable Emissions _2___ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 72.43 lb/hour	4. Equivalent Allowable Emissions: 72.43 lb/hour 10.43 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Stack testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of Fuel oil firing. OTHER Explanation : BACT.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units – Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing 20.60 lb/hour 90.23 tons/year Fuel Oil Firing 62.10 lb/hour 8.94 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
9. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 20.60 lb/hr * 8760 hr/yr * 1/2000 lb = 90.23 tons per year Fuel Oil Firing: 62.10 lb/hr * 288 hr/yr* 1/ 2000 lb = 8.94 tons per year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of __1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period - Fuel monitoring schedule. - VE Limitation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 1.22 lb/hour 5.34 tons/year Fuel Oil Firing 109.35 lb/hour 15.74 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
16. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 1.22 lb/hr * 8760 hr/yr * 1/2000 lb = 5.34 tons per year Fuel Oil Firing: 109.35 lb/hr * 288 hr/yr* 1/ 2000 lb = 15.74 tons per year	
17. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.22 lb/hour	4. Equivalent Allowable Emissions: 1.22 lb/hour 5.34 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

Allowable Emissions Allowable Emissions _2____ of __2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 109.35 lb/hour	4. Equivalent Allowable Emissions: 109.35 lb/hour 15.74 tons/year

5. Method of Compliance (limit to 60 characters):
- Record Keeping – hours of operation per fuel type per 12 month period

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

288 hours/yr of Fuel oil firing.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 4.77 lb/hour 20.89 tons/year Fuel Oil Firing 8.14 lb/hour 1.17 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor:	7. Emissions Method Code: 0
18. Calculation of Emissions (limit to 600 characters): Potential annual emissions: Natural Gas Firing: 4.77 lb/hr * 8760 hr/yr * 1/2000 lb = 20.89 tons per year Fuel Oil Firing: 8.14 lb/hr * 288 hr/yr* 1/ 2000 lb = 1.17 tons per year	
19. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _1____ of _2___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 4.77 lb/hour	4. Equivalent Allowable Emissions: 4.77 lb/hour 20.89 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 8,760 hours of Natural gas firing.	

Allowable Emissions Allowable Emissions _2____ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 8.14 lb/hour	4. Equivalent Allowable Emissions: 8.14 lb/hour 1.17 tons/year
5. Method of Compliance (limit to 60 characters): - Record Keeping – hours of operation per fuel type per 12 month period	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 288 hours/yr of Fuel oil firing.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ___1___of___1___

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - stack testing (USEPA Method 9 Visual Determination of Opacity) - VE limit proposed in lieu of PM/PM_{10} pound per hour limit.	
5. Visible Emissions Comment (limit to 200 characters): Florida Air Regulation: Rule 62.296	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ___1__ of ___6_

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): Rule: 40 CFR Part 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor ___2__ of ___6_

1. Parameter Code: WTF	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Rule: New Source Performance Standards 40 CFR 60, Subpart GG	

Continuous Monitoring System: Continuous Monitor __3__ of __6_

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number:
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor __4__ of __6_

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement: Later	[ ] Rule [X] Other
4. Monitor Information: Later Manufacturer: Later Model Number:Later	Serial Number: Later
5. Installation Date: Later	6. Performance Specification Test Date: Later
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. Natural Gas flow monitor installed pursuant to 40 CFR 75.	

Continuous Monitoring System: Continuous Monitor __5__ of __6__

1. Parameter Code: O2	2. Pollutant(s):	
3. CMS Requirement:	[X] Rule	[ ] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number: Later	
5. Installation Date: Later	6. Performance Specification Test Date: Later	
7. Continuous Monitor Comment (limit to 200 characters): CMS will be installed before operation of the emission source. This CMS will be installed on the HRSG stack. Required by 40 CFR Part 75.		

Continuous Monitoring System: Continuous Monitor __6__ of __6__

1. Parameter Code: VE	2. Pollutant(s):	
3. CMS Requirement:	[ ] Rule	[X] Other
4. Monitor Information: Later Manufacturer: Later Model Number: Later	Serial Number: Later	
5. Installation Date: Later	6. Performance Specification Test Date: Later	
7. Continuous Monitor Comment (limit to 200 characters): CMS for Opacity will be installed before operation of the emission source. This CMS will be installed on the HRSG stack. Required by 40 CFR Part 75.		

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment E [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: SCA BACT Analysis Appendix 10.7, Section 3.0
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment F [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date: [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: SCA PSD Application Appendix 10.7 [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment: None

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:__________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: Attachment G [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

Attachment A
Facility Applicable Regulations

List of Applicable Regulations

FDEP Title V Core List (effective 3/25/95) incorporated by reference

40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources

40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines

Part 70 – State Operating Permit Programs

Section 70.1 - Program Overview

Section 70.2 - Definitions

Section 70.3 - Applicability

Section 70.4 - State Program Submittals and Transition

Section 70.5 - Permit Applications

Section 70.6 - Permit Content

Section 70.7 - Permit Issuance, Renewal, Reopenings, and Revisions

Section 70.8 – Permit Review by the EPA and Affected States

Section 70.9 – Fee Determination and Certification

Section 70.10 – Federal Oversight and Sanctions

Section 70.11 – Requirements for Enforcement Authority

Part 72 – Regulations on Permits

Subpart A – Acid Rain program General Provisions

Section 72.1 Purpose and Scope

Section 72.2 – Definitions

Section 72.3 – Measurements, Abbreviations, and Acronyms

Section 72.4 – Federal Authority

Section 72.5 – State Authority

Section 72.6 – Applicability

Section 72.9 – Standard Requirements

Section 72.10 – Availability of Information

Section 72.11 – Computation of Time

Section 72.12 – Administrative Appeals

Section 72.13 – Incorporation by Reference

Subpart B – Designated Representative

Section 72.20 – Authorization and Responsibilities of the Designated

Section 72.21 – Submissions

Section 72.22 – Alternate Designed Representative

Section 72.23 – Changing the Seignated Representative, Alternate Designated

Section 72.24 – Certificate of Representation

Section 72.25 – Objections

Subpart C – Acid Rain Application

Section 72.30 – Requirements to Apply

Section 72.31 – Information Requirements for Acid Rain Permit

Section 72.32 – Permit Application Shield and Binding Effect of Permit

Section 72.33 – Identification if Dispatch System

Subpart D – Acid Rain Compliance Plan and Compliance Options

Section 72.40 – General

Subpart E – Acid Rain Permit Conditions

Section 72.50 – General

Section 72.51 – Permit Shield

Subpart F – Federal Acid Rain Permit Issuance Procedure

Section 72.60 – General

Section 72.61 – Completeness

Section 72.62 – Draft Permit

Section 72.63 – Administrative Board

Section 72.64 – Statement of Basis

Section 72.65 – Public Notice of Opportunities for Public Comment
Section 72.66 – Public Comments

Section 72.67 – Opportunity for Public Hearing

Section 72.68 – Response to Comments

Section 72.69 – Issuance and effective Date of Acid Rain Permits

Subpart G – Acid Rain Phase II Implementation

Section 72.70 – Relationship to Title V Operating Permit Program

Section 72.71 – Approval of State Programs – General

Section 72.72 – State Permit Program Approval Criteria

Section 72.73 – State Issue of Phase II Permits

Section 73.35 – Compliance

Section 73.36 – Banking

Section 73.37 – Account Error and Dispute Resolution

Section 73.38 – Closing of Accounts

Subpart D – Allowance Transfers

Section 73.50 – Scope and Submission of Transfers

Section 73.51 – Prohibition

Section 73.52 – EPA Recordation

Section 73.53 – Notification

Subpart E – Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 – Auctions

Section 73.71 – Bidding

Section 73.72 – Direct Sales

Section 73.73 – Selegation of Auctions and Sales and Termination of Auctions

Section 73.74 – Independent Power Producers Written Guarantee

Section 73.75 – Application for an IPP Written Guarantee

Section 73.76 – Approval and Exercise of the IPP Written Guarantee

Section 73.77 – Relationship of Independent Power Producers Written Guarantee

Section 75.5 – Prohibitions

Section 75.6 – Incorporation by Reference

Section 76.7 – EPA Study

Section 76.8 – [Reserved]

Subpart – Monitoring Provisions

Section 75.10 – General Operating Requirements

Section 75.11 – Specific Provisions for Monitoring SO2 Emissions

Section 75.12 – Specific Provisions for Monitoring NOx Emissions (NOx and Flow)

Section 75.13 – Specific Provisions for Monitoring CO2 Emissions

Section 75.14 – Specific Provisions for Monitoring Capacity

Section 75.15 – Specific Provisions for Monitoring SO2 Emissions Removal By

Section 75.16 – Specific Provisions for Monitoring Emissions from Common, By

Section 76.6 – NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 – Revised NOx Emission Limitations for Group 1, Phase II Boilers

Section 76.8 – Early Election for Group 1, Phase II Boilers

Section 76.9 – Permit Application and Compliance Plans

Section 76.10 – Alternative Emission Limitations

Section 76.11 – Emissions Averaging

Section 76.12 – Phase I NOx Compliance Extensions

Section 76.13 – Compliance and Excess Emissions

Section 76.14 – Monitoring, Recordkeeping, and Reporting

Section 76.15 – Test Methods and Procedures

Section 76.16 – [Reserved]

Part 77 – Excess Emissions

State Applicable Requirements

Chapter 62-4, F.A.C.; PERMITS

62-4.055 – Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES – GENERAL REQUIREMENTS

62-210.550 – Stack Height Policy

62-210.700 Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES – PRECONSTRUCTION REVIEW

62-212.300 – General Preconstruction Review Requirements

62-212.400 – Prevention of Significant Deterioration

62-212.410 – Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 – Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN PR

62-214.300 – Applicability

62-214.320 – Applications

62-214.330 – Acid Rain Compliance Plan and Compliance Options

62-214.350 – Certification

62-214.370 – Revisions Administration Corrections

62-214.420 – Acid Rain Part Content

62-214.430 – Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 – Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 – Air Pollution Episodes

62-273.400 – Air Alert

62-273.500 – Air Warning

62-273.600 – Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES – EMISSION STANDARDS

62-296.405 – Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES – EMISSIONS MONITORING

62-297.401 – Compliance Test Methods

62-297.440 – Supplementary Test Procedures

62-297.520 – EPA Performance Specifications

62-297.620 – Exceptions and Approval of Alternate Procedures and Requirements

62-297.310 – General Test Requirements

Subpart F – Energy Conservation and Renewable Energy Reserve

Section 73.80 – Operation of Allowance Reserve Program for Conservation..

Section 73.81 – Quantified Conservation Measures and Renewable Energy

Section 73.82 – Application for Allowances from Reserve Program

Section 73.83 – Secretary of Energy's Action on New Income Neutality

Section 73.84 – Administrator's Action on Applications

Section 73.85 – Administrator Review of the Reserve Program

Section 73.86 – State Regulatory Autonomy, Appendix A to Subpart F….List of

Part 75 – Emission Monitoring

Subpart A – General

Section 75.1 – Purpose and Scope

Section 75.2 – Applicability

Section 75.3 – General Acid Rain Program Provisions

Section 75.4 – Compliance Dates

Subpart C – Operation and Maintenance Requirements

Section 75.20 – Certification and Recertification Procedures

Section 75.21 – Quality Assurance and Quality Control Requirements

Section 75.22 – Reference Test Methods

Section 75.23 – Alternatives to ASTM Methods

Section 75.24 – Out-of-Control Periods

Subpart D – Missing Data Substitution Procedures

Section 75.30 – General Procedures

Section 75.31 – Initial Missing Data Procedures

Section 75.32 – Determinations of Monitor Data Availability for Standard Missing Data

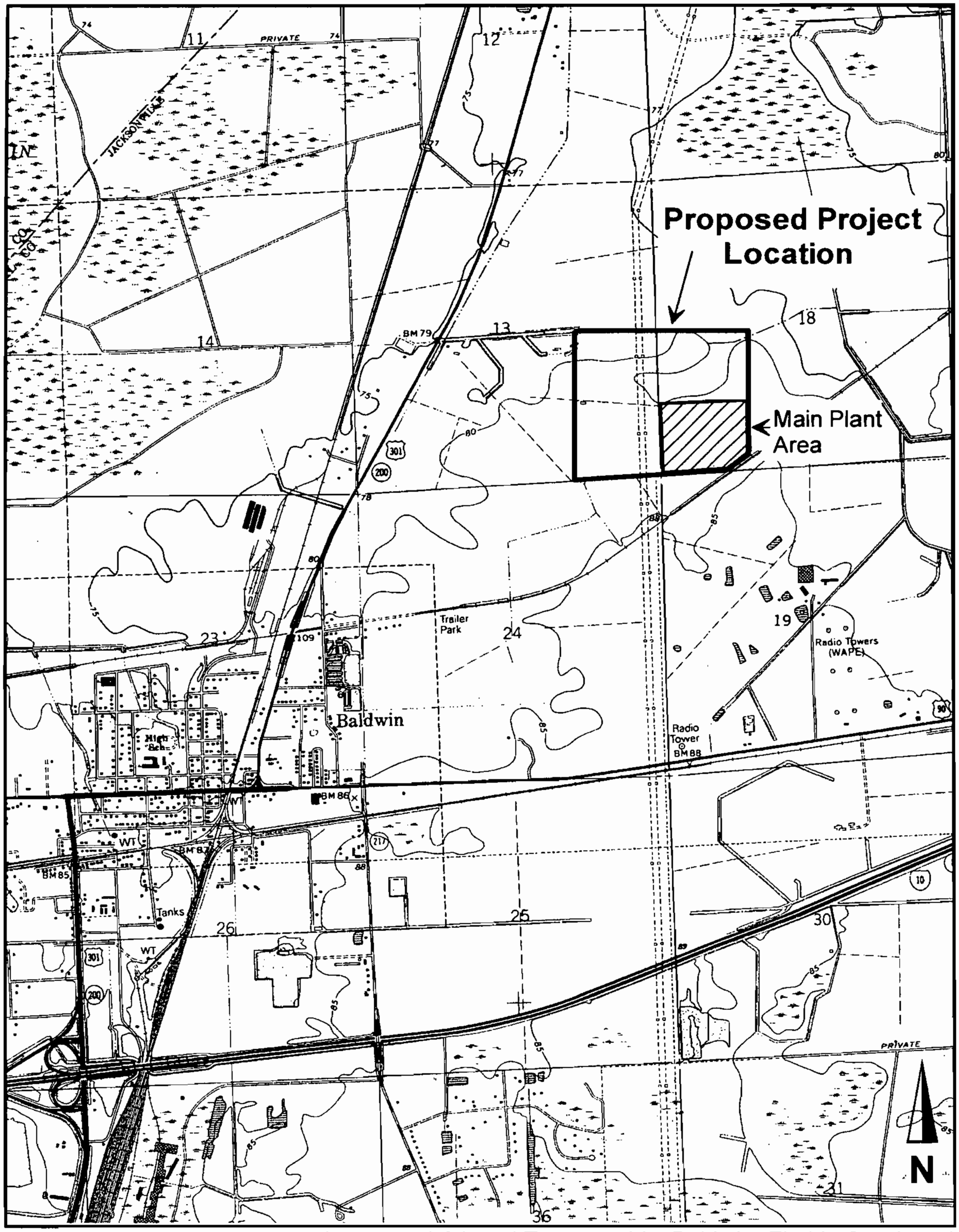
Section 75.33 – Standard Missing Data Procedures

Section 75.34 – Units with Add-on Emission Controls

Subpart E – Alternative Monitoring Systems

Subpart 75.40 – General Demonstration Requirements

Attachment B
Area Map Showing Facility Location

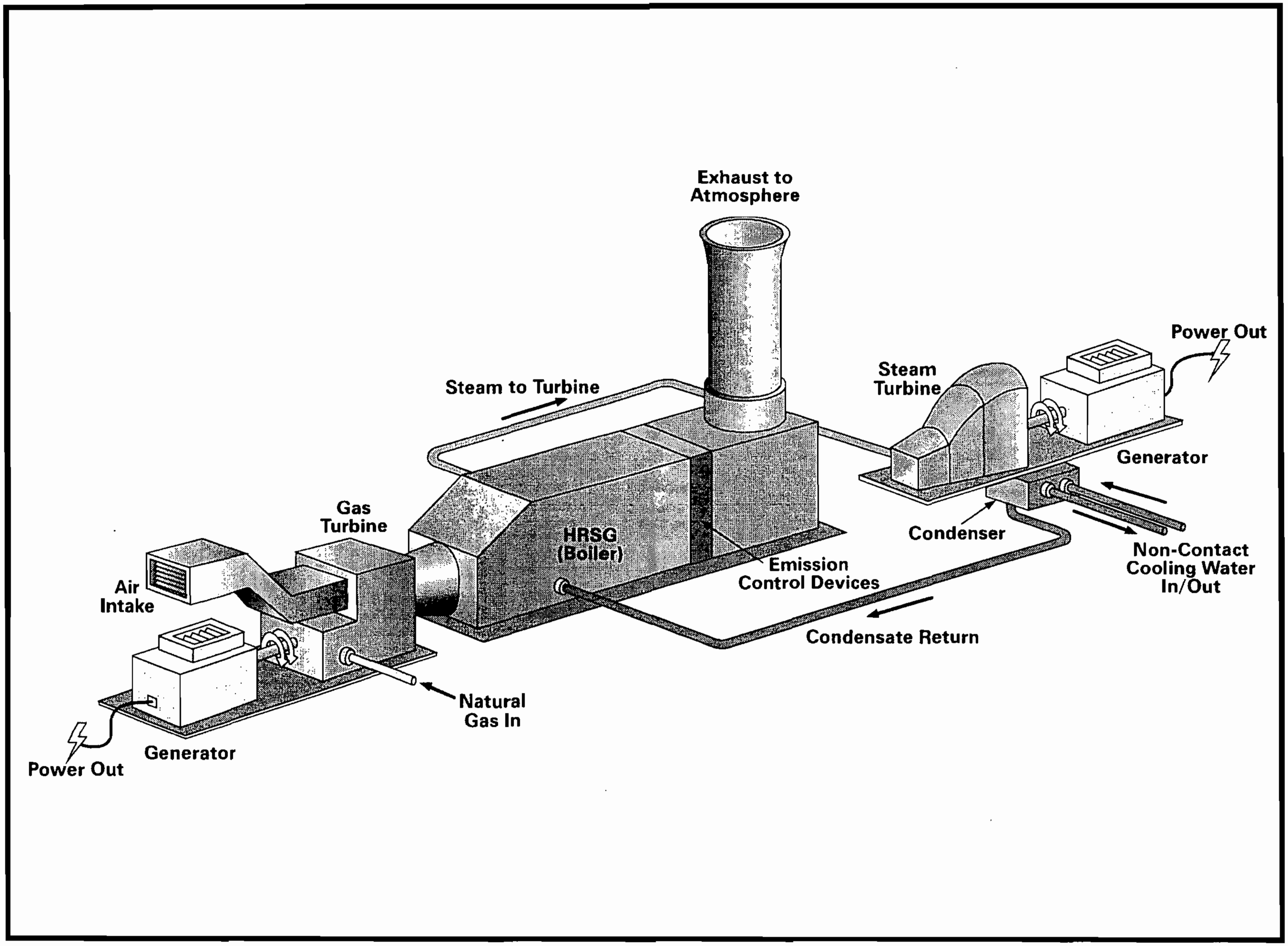


Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Attachment C
Facility Plot Plan

Attachment D
Process Flow Diagram



Exhaust to
Atmosphere
Steam to Turbine
Steam
Turbine
Power Out
Generator
Condenser
Non-Contact
Cooling Water
In/Out
Gas
Turbine
HRSG
(Boiler)
Emission
Control Devices
Air
Intake
Condensate Return
Natural
Gas In
Generator
Power Out

Attachment E
Fuel Analysis

Fuel is specified as pipeline quality sweet natural gas and No. 2 fuel oil containing no more than 0.05 percent sulfur.

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FLORIDA GAS TRANSMISSION COMPANY
FERC Gas Tariff
Third Revised Volume No. 1

Third Revised Sheet No. 102C
Superseding
Second Revised Sheet No. 102C

GENERAL TERMS AND CONDITIONS
(continued)

am. GISB Definitions - shall mean any such definitions issued by GISB which have been adopted by the FERC. Transporter incorporates GISB Definitions (Version 1.3, July 31, 1998) 1.2.8 through 1.2.12 and 4.2.1 through 4.2.8 by reference herein.

2. QUALITY

A. Gas delivered by Shipper or for its account into Transporter's pipeline system at receipt points shall conform to the following quality standards:

1. shall be free from objectionable odors, solid matter, dust, gums, and gum forming constituents, or any other substance which might interfere with the merchantability of the gas stream, or cause interference with proper operation of the lines, meters, regulators, or other appliances through which it may flow;

2. shall contain not more than seven (7) pounds of water vapor per one thousand (1,000) MCF;

3. shall contain not more than one quarter (1/4) grain of hydrogen sulphide per one hundred (100) cubic feet of gas;

4. shall contain not more than ten (10) grains of total sulphur per one hundred (100) cubic feet of gas;

5. shall contain not more than a combined total three percent (3%) by volume of carbon dioxide and/or nitrogen;

6. shall contain not more than one quarter percent (1/4%) by volume of oxygen;

Issued by: Robert B. Kilmer, Vice President
Issued on: July 1, 1999 Effective: August 1, 1999

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SPECIFICATIONS FOR #2 LOW SULFUR DIESEL FUEL

The oil shall be hydrocarbon oil, free from alkali, mineral acid, grit, fibrous or other foreign matter and shall meet the following physical and chemical properties:

1) Gravity: A.P.I. 30 minimum (ASTM D287)

2) Flash: 130 F minimum (ASTM D93)

3) Viscosity: Kinematic, Centistokes at 100 F, minimum 2.0, maximum 3.0 (ASTM D445)

4) Water & Sediment: .50% maximum, (ASTM D1796 or D2700)

5) Pour Point: 0 F maximum (ASTM D97)

6) Distillation: 10% Point, 480 F maximum, 90% Point, 640 F maximum, End Point 690 F maximum (ASTM D86)

7) **Sulfur: Low Sulfur - 0.05% maximum (ASTM D129 or D1552),**

8) BTU: minimum 138,000 BTU's per gallon (ASTM D240)

9) Carbon Residue on 10% bottoms: .25 Max (ASTM D189)

10) Trace Metals (PPM, Max):
- Calcium 4.0
- Lead 1.0
- Potassium 2.0
- Vanadium 1.5.

Attachment F
Stack Sampling Facilities

"The stack sampling facilities will be installed in accordance with Rule 62-297.310 (6)."

Attachment G
Acid Rain Permit Application

JEA

December 30, 1999

Mr. Scott Sheplak, P.E.
Title V Administrator
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee. FL 32399-2400

RE: Brandy Branch Facility
Acid Rain Application Forms

Dear Mr. Sheplak:

Enclosed please find the Acid Rain Application Forms for the Brandy Branch Facility.

If you have any questions with regard to this matter, please contact me at (904) 665-6247.

Sincerely.

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: USEPA
USEPA, Region 4

bc: J. Connolly
E. Mims
L. Starner
B. Gianazza
File

bbacidrain

BEST AVAILABLE COPY

Phase II Permit Application

Page 1

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name Brandy Branch State FL ORIS Code 7846

STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a	Compliance Plan b	Compliance Plan c	d	e
Boiler ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
001	Yes		Dec. 2000	Dec. 2000
002	Yes		Dec. 2000	Dec. 2000
003	Yes		Dec. 2001	Dec. 2001
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes for any unit

☐ For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

Plant Name (from Step 1) **Brandy Branch**

TEP 4
ead the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1) **Brandy Branch**

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Jon P. Eckenbach		
Signature		Date	12-14-99

STEP 5 (optional)
Enter the source AIRS
FINDS identification

AIRS
FINDS

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: [X] New [ ] Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 [ ]

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name	State	ORIS Code
Brandy Branch	FL	7846

STEP 2
Enter requested information for the designated representative.

Name: Jon P. Eckenbach

Address: 21 West Church Street
Jacksonville, Florida 32202

Phone Number: (904) 665-6315

Fax Number: (904) 554-7366

E-mail address (if available): eckejp@jea.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name: Tim E. Perkins

Phone Number: (904) 665-4520

Fax Number: (904) 665-7376

E-mail address (if available): perkte@jea.com

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1) Brandy Branch

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date 12-14-99
Signature (alternate designated representative) J E Perkins	Date 12-16-99

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name JEA					[X] Owner	[X] Operator
ID# 001	ID# 002	ID# 003	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

January 19, 2000

Mr. N. Bert Gianazza, P.E.
Environmental Permitting & Compliance Group
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Acid Rain Phase II Permit Application
Brandy Branch Facility; ORIS Code: 7846

Dear Mr. Gianazza:

Thank you for your recent submission of the Acid Rain Phase II Permit Application for the subject facility. We have reviewed the document and found it to be complete.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Section

cc: Jenny Jachim, EPA Region 4

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☒ Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 ☐

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name Brandy Branch	State FL	7846 ORIS Code

STEP 2
Enter requested information for the designated representative.

Name Jon P. Eckenbach, Executive Vice President	
Address 21 West Church Street Jacksonville, FL 32202	
Phone Number (904) 665-6315	Fax Number (904) 665-7366
E-mail address (if available) eckejp@jea.com	

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name Susan Hughes, Vice President	
Phone Number (904) 665-6248	Fax Number (904) 665-7376
E-mail address (if available) hughsn@jea.com	

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1) Brandy Branch

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date 11/14/00
Signature (alternate designated representative)	Date 11/17/00

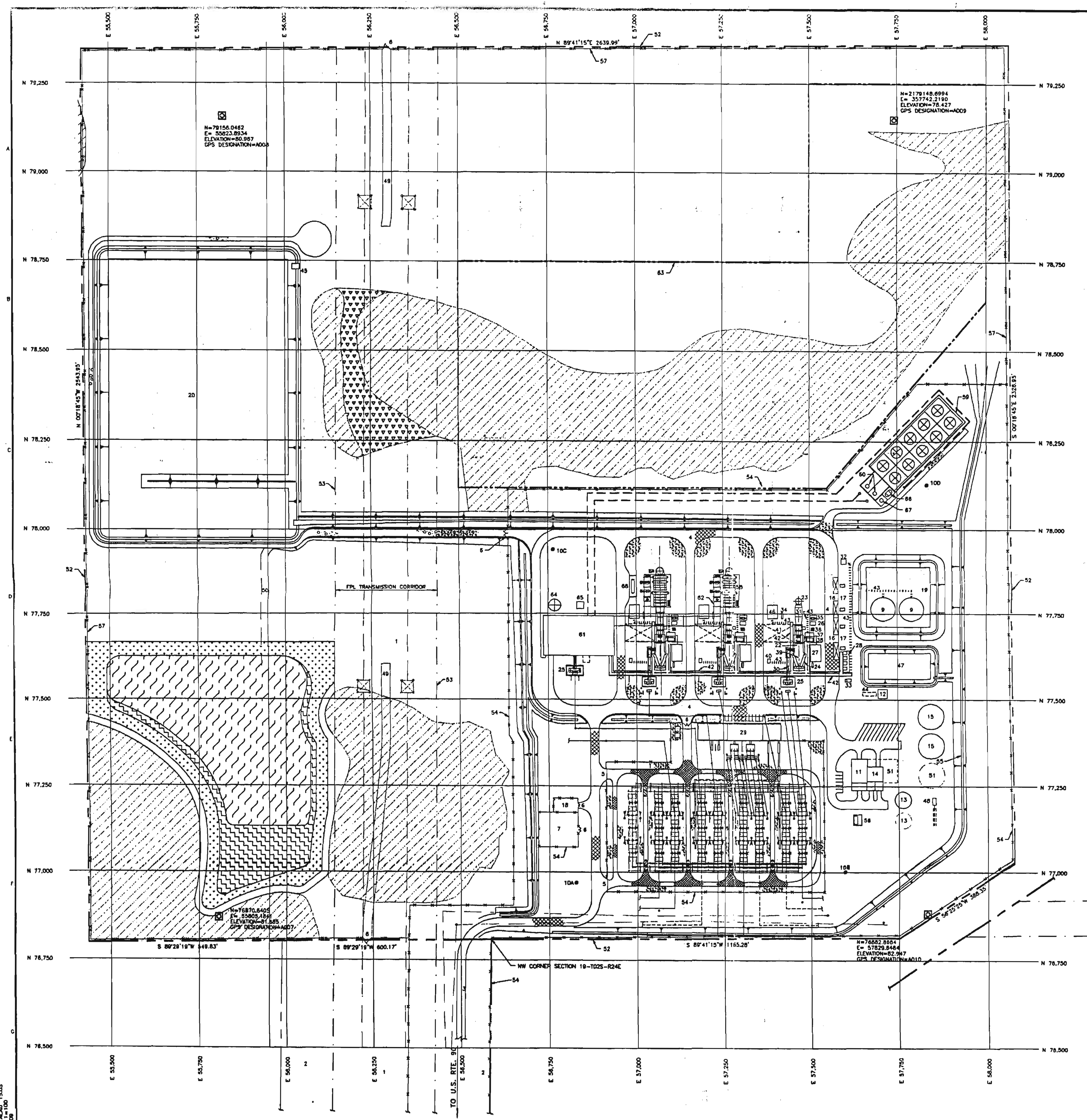
STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name JEA					☒ Owner	☒ Operator
ID# 1	ID# 2	ID# 3	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	LOCATION COORDINATES EAST	REFERENCE LOCATION
1	F.P.&L. RIGHT-OF-WAY	N/A	N/A	
2	JEA TRANSMISSION CORRIDOR	N/A	N/A	
3	ACCESS ROAD	N/A	N/A	
4	LOOP ROAD	N/A	N/A	
5	SLIDE GATE	N/A	N/A	
6	SWING GATE	N/A	N/A	
7	FUEL GAS METERING STATION	N/A	N/A	
8	SUBSTATION AREA	N/A	N/A	
9	FUEL OIL STORAGE TANK (1,000,000 GALLONS)	N/A	N/A	
10A	WATER SUPPLY WELL	76970.00	56825.00	CL WELL
10B	WATER SUPPLY WELL	77001.92	57597.00	CL WELL
10C	WATER SUPPLY WELL	77943.00	567645.00	CL WELL
10D	WATER SUPPLY WELL	78129.00	57834.00	CL WELL
11	SHOP/STORAGE BUILDING	N/A	N/A	
12	WASTEWATER PUMPING STATION	N/A	N/A	
13	RAW WATER/FIRE WATER STORAGE TANK	N/A	N/A	
14	MECHANICAL EQUIPMENT BUILDING	N/A	N/A	
15	DEMINERALIZED WATER STORAGE TANK	N/A	N/A	
16	FUEL OIL UNLOADING AREA	N/A	N/A	
17	FUEL OIL UNLOADING PUMP AREA	N/A	N/A	
18	HYDROGEN STORAGE GAS AREA	N/A	N/A	
19	FUEL OIL STORAGE TANK SECONDARY CONTAINMENT	N/A	N/A	
20	STORM WATER DETENTION POND	N/A	N/A	
21	COMBUSTION TURBINE (CT)	N/A	N/A	
22	CT GENERATOR	N/A	N/A	
23	CT EXHAUST STACK (UNIT 1)	77788.26	57469.00	CL STACK
23	CT EXHAUST STACK (UNIT 2)	N/A	N/A	
23	CT EXHAUST STACK (UNIT 3)	N/A	N/A	
24	CT AIR INLET FILTER	N/A	N/A	
25	GENERATOR STEP-UP TRANSFORMER	N/A	N/A	
26	CT WATER INJECTION SKID	N/A	N/A	
27	CONTROL/ELECTRICAL BUILDING	N/A	N/A	
28	FUEL FORWARDING SKIDS	N/A	N/A	
29	CONTROL/SHARED SERVICES BUILDING	N/A	N/A	
30	UNIT AUXILIARY TRANSFORMER	N/A	N/A	
31	EXHAUST DUCT SILENCER	N/A	N/A	
32	FIRE PROTECTION FOAM HOUSE	N/A	N/A	
33	WASH WATER SKID	N/A	N/A	
34	MISCELLANEOUS DRAIN TANK	N/A	N/A	
35	CT CO2 FIRE PROTECTION SKID	N/A	N/A	
36	FALSE START DRAIN TANK	N/A	N/A	
37	LIQUID FUEL/ATOMIZING AIR MODULE	N/A	N/A	
38	CT ACCESSORY MODULE	N/A	N/A	
39	GENERATOR COMPARTMENT	N/A	N/A	
40	FIRE WATER DELUGE HOUSE	N/A	N/A	
41	MAINTENANCE AREA	N/A	N/A	
42	PIPE TRENCH	N/A	N/A	
43	SLEEPER PIPE RACK	N/A	N/A	
44	OIL WATER SEPARATOR	N/A	N/A	
45	STORM WATER DETENTION POND DISCHARGE STRUCTURE	N/A	N/A	
46	COOLER	N/A	N/A	
47	PERCOLATION POND	N/A	N/A	
48	SEPTIC TANK AND DRAINFIELD DETAIL	N/A	N/A	
49	EXISTING ROAD	N/A	N/A	
50	TEMPORARY CONSTRUCTION ACCESS ROAD	N/A	N/A	
51	FUTURE WATER TREATMENT EQUIPMENT EXPANSION	N/A	N/A	
52	PROPERTY BOUNDARY	N/A	N/A	
53	EASEMENT BOUNDARY	N/A	N/A	
54	CHAIN LINK SECURITY FENCE	N/A	N/A	
55	PERIMETER DITCH	N/A	N/A	
56	LUBE OIL STORAGE AREA	N/A	N/A	
57	BARBED WIRE SITE PERIMETER FENCE	N/A	N/A	
58	HEAT RECOVERY STEAM GENERATOR	N/A	N/A	
59	COOLING TOWER	N/A	N/A	
60	CIRCULATING WATER PUMPS	N/A	N/A	
61	STEAM TURBINE GENERATOR BUILDING	N/A	N/A	
62	ABOVE GROUND PIPE RACK	N/A	N/A	
63	CONSERVATION EASEMENT	N/A	N/A	
64	CONDENSATE STORAGE TANK	N/A	N/A	
65	WASTEWATER SUMP	N/A	N/A	
66	CIRCULATING WATER ACID TANK	N/A	N/A	
67	CIRCULATING WATER HYPOCHLORITE TANK	N/A	N/A	
68	AMMONIA STORAGE TANK	N/A	N/A	

GENERAL LEGEND

- BENCHMARK
- FUTURE FACILITY
- WETLANDS
- CYPRESS (ZONE 2) AREA
- ASPHALT
- CRUSHED ROCK SURFACING
- HERBACEOUS (ZONE 1) AREA
- UPLAND SEEDING AREA
- RESTORATION MITIGATION AREA
- GEOWEB

NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE		
C	10-13-2000	GENERAL REVISIONS	WG	JWS
B	09-19-2000	GENERAL REVISIONS	WG	SKW
A	09-05-2000	ISSUED FOR REVIEW	WG	SKW

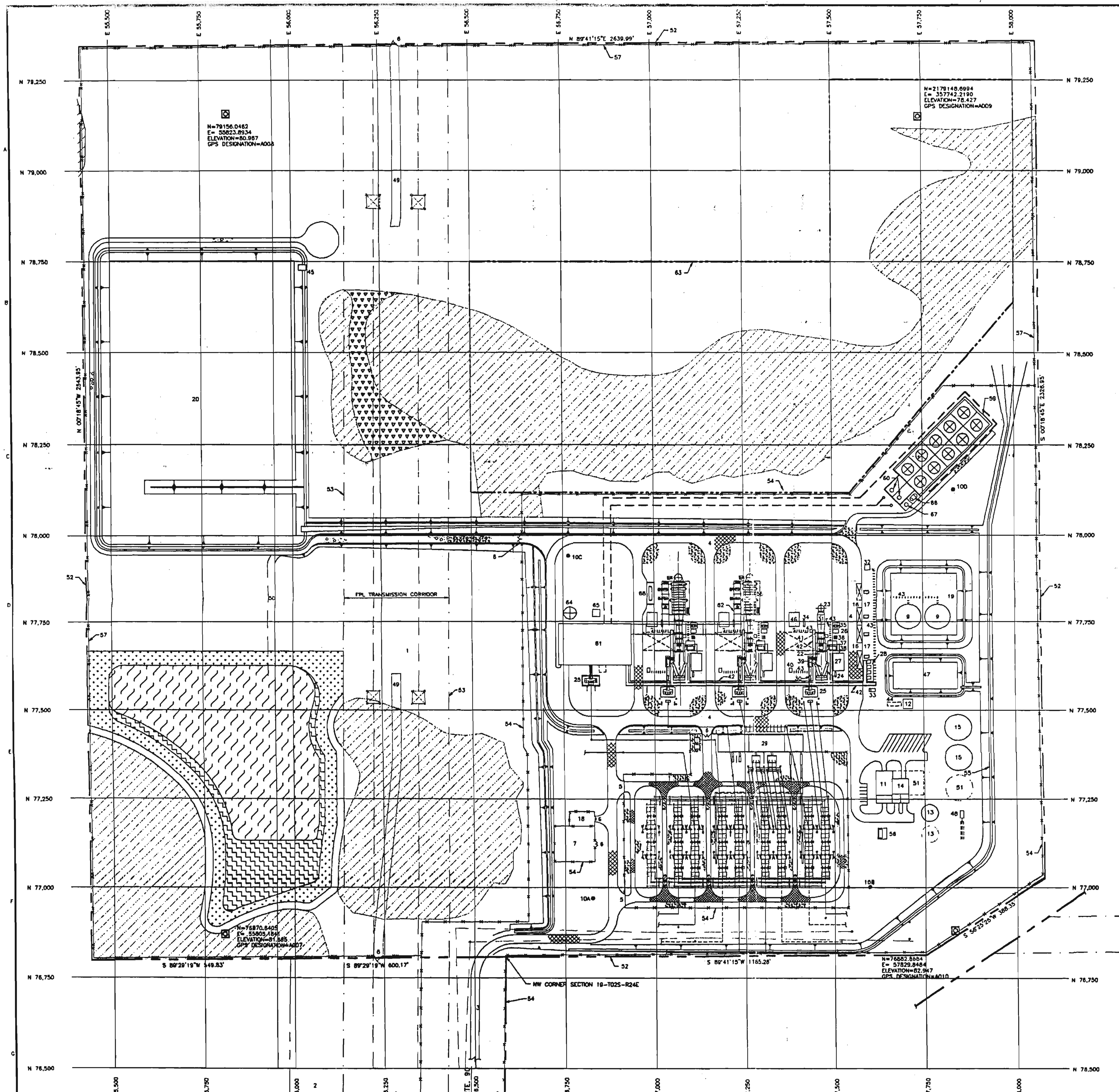
SCALE: 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH
JEA Building Community
ENGINEER SKW DRAWN WG
CHECKED DATE

JEA
BRANDY BRANCH COMBINED CYCLE PROJECT
SITE ARRANGEMENT

PROJECT DRAWING NUMBER: 97990-DS-0001
REV: C



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5	SLIDE GATE	N/A	N/A	
6	SWING GATE	N/A	N/A	
7	FUEL GAS METERING STATION	N/A	N/A	
8	SUBSTATION AREA	N/A	N/A	
9	FUEL OIL STORAGE TANK (1,000,000 GALLONS)	N/A	N/A	
10A	WATER SUPPLY WELL	76970.00	56825.00	CL WELL
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14	MECHANICAL EQUIPMENT BUILDING	N/A	N/A	
15	DEMINERALIZED WATER STORAGE TANK	N/A	N/A	
16	FUEL OIL UNLOADING AREA	N/A	N/A	
17	FUEL OIL UNLOADING PUMP AREA	N/A	N/A	
18	HYDROGEN STORAGE GAS AREA	N/A	N/A	
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43	SLEEPER PIPE RACK	N/A	N/A	
44	OIL WATER SEPARATOR	N/A	N/A	
45	STORM WATER DETENTION POND DISCHARGE STRUCTURE	N/A	N/A	
46	COOLER	N/A	N/A	
47	PERCOLATION POND	N/A	N/A	
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65	WASTEWATER SUMP	N/A	N/A	
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67	CIRCULATING WATER HYPOCHLORITE TANK	N/A	N/A	
68	AMMONIA STORAGE TANK	N/A	N/A	

GENERAL LEGEND

- BENCHMARK
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NOT TO BE USED
FOR CONSTRUCTION

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B	09-19-2000	GENERAL REVISIONS	WG	SKW			
A	09-05-2000	ISSUED FOR REVIEW	WG	SKW			

100' 50' 0 100' 200'
SCALE: 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH
JEA Building Community
ENGINEER SKW DRAWN WG
CHECKED DATE

JEA
BRANDY BRANCH COMBINED CYCLE PROJECT
SITE ARRANGEMENT

PROJECT: 97990-DS-0001 DRAWING NUMBER
REV: C
CODE