Reliant Energy Osceola, L.L.C.
Osceola Power Project

Construction Permit Application
July 1999

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PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION FOR THE OSCEOLA POWER PROJECT

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1.0 Introduction

Reliant Energy Osceola, L.L.C. proposes to develop a new electrical power generating project in Osceola County (herein after referred to as the Project) near Holopaw, Florida. The proposed Project will be composed of three simple cycle combustion turbines (SCCT) rated at a nominal 170 MW each, firing natural gas and No. 2 distillate fuel oil. New support facilities for the Project will include water and wastewater treatment facilities, water storage tanks, a storm water detention pond, a switchyard and electrical interconnections to an existing nearby substation, and a fuel oil storage tank.

This report is 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 Project.

2.0 Project Characterization

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

2.1 Project Location

The Project is located in a rural part of northern Osceola County, Florida. Figure 2-1 shows the general location of the Project which is approximately 1 mile northwest of Holopaw. The nearest Federal PSD Class I Area is the Chassahowitzka National Wilderness Area located approximately 155 km northwest of the Project. The topography of the area is generally unpronounced and relatively flat.

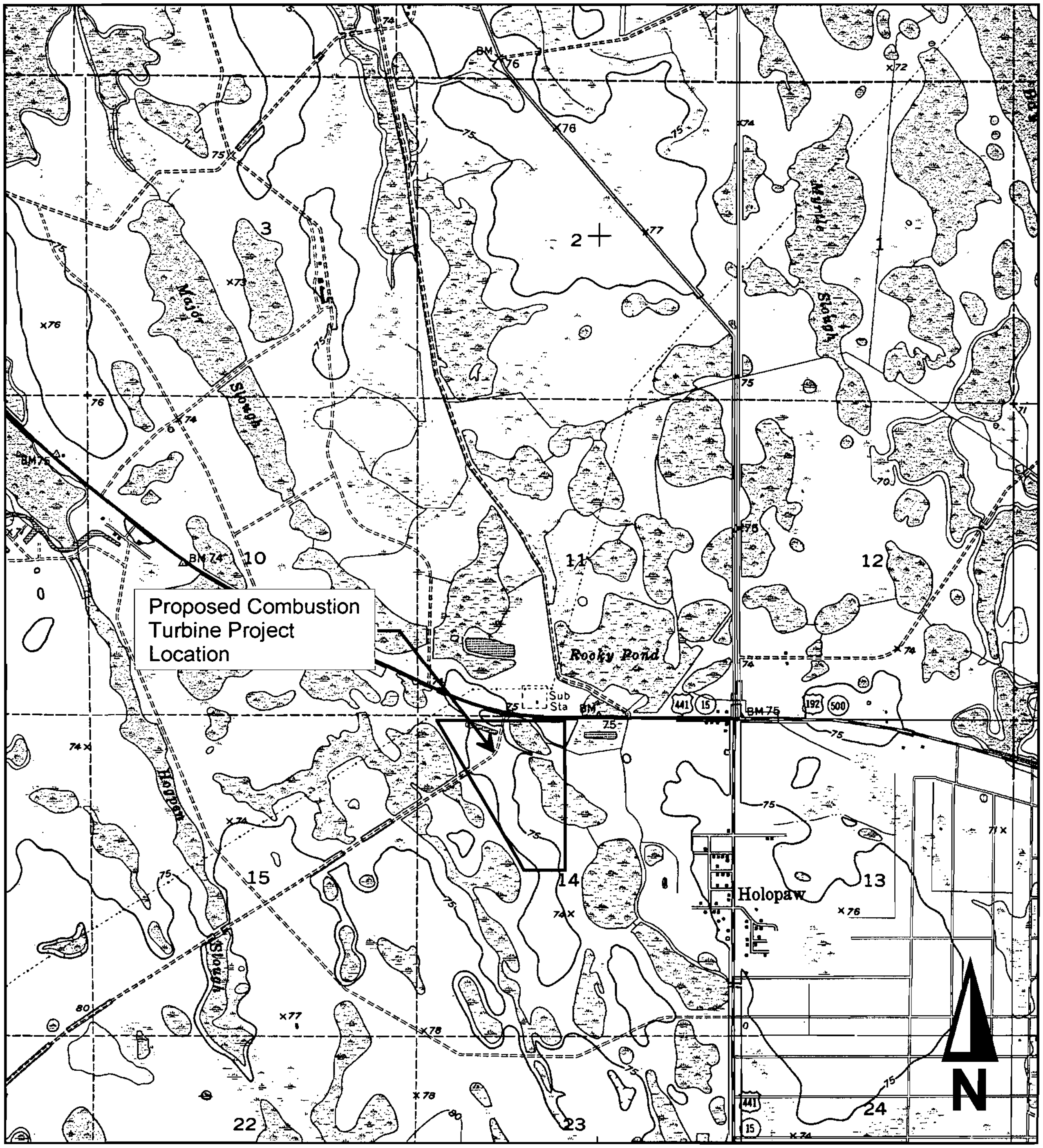
2.2 Project Description

The Project will be composed of three SCCTs. The SCCT proposed for the Project is a General Electric Frame 7FA simple cycle combustion turbine (Model PG7241FA) firing natural gas and No. 2 distillate fuel. The energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as they expand through the turbine section of each SCCT. The rotating mechanical energy will be converted into electrical energy via a shaft on the SCCT that is connected to an electrical generator. The remaining combustion gases will be exhausted to the atmosphere through an exhaust stack.

2.3 Project Emissions

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

- Three SCCTs firing natural gas and No. 2 distillate fuel.
- One No. 2 distillate fuel oil storage tank of approximately 3,000,000 gallons capacity.
- A diesel-fired emergency fire water pump.



Base Map: 7.5' Quadrangle
Holopaw, Florida

Reliant Energy Osceola, L.L.C. Proposed
Combustion Turbine Project Location

Figure 2-1

2.3.1 SCCT Emissions

Performance data for the SCCTs, based on vendor data from GE at design loads of 60, 80, and 100 percent while firing natural gas and distillate fuel at ambient air temperatures of 19°F, 59°F, and 94°F, are provided in Attachment 1. Ambient temperature data were selected based on meteorological data representing winter seasonal site temperatures, which correspond to maximum heat input and power generation, average annual site temperatures representative of the average heat input rate, and summer seasonal site temperatures that correspond to the lowest heat input rate. The maximum pound per hour emission rates considering all ambient temperatures and partial load operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.3.2 No. 2 Distillate Fuel Oil Storage Tank

The fuel oil storage tank is estimated to have a capacity of 3,000,000 gallons. Emissions of VOCs from the fuel oil storage tank were estimated at less than 1.0 tpy.

2.4 Maximum Project Potential to Emit

The proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. The potential to emit was calculated from the maximum hourly emission rate for each pollutant at an ambient temperature of 59°F (average annual) considering 60 to 100 percent load simple cycle operation, 3,000 hours per year per CT. This total includes up to 2,000 hours of distillate fuel oil firing (0.05 % sulfur) with the balance of the firing on natural gas. The Project's potential to emit for each pollutant is summarized in Table 2-2. 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 3.

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 Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

Table 2-1 Project Maximum Emission Rates (lb/h)*		
Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NOx	73.5	343.0
SO2	1.1	104.3
CO	36.2	70.0
PM/PM10	18.0	34.0
VOC	3.0	8.0
*Maximum pound per hour emission rates for the SCCTs considering worst-case ambient temperature and partial load operation for natural gas and distillate fuel oil firing.		

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NOx	1,074.0[a]	40	**yes**
SO_2	296.8[a,b]	40	**yes**
CO	245.7[a]	100	**yes**
PM/PM_{10}	129.0[a,c]	25/15	**yes**
VOC	26.7[a,e]	40	no
Sulfuric Acid Mist	45.5[a,d]	7	**yes**
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	Negl.	10	no
Vinyl Chloride	Negl.	1	no
Total Fluorides	Negl.	3	no
Mercury	Negl.	0.1	no
Beryllium	Negl.	0.0004	no
Lead	Negl.	0.6	no

[a]Based on maximum lb/h emission rate at 59°F conditions for all loads and operating scenarios; assuming 1,000 and 2,000 hours per year of natural gas and distillate fuel oil firing, respectively.

[b]Based on 0.05% sulfur distillate fuel oil, 0.2 gr/100 scf sulfur natural gas, and assuming 100 percent conversion to SO_2.

[c]Assumes front and back half PM/PM_{10} emissions.

[d]Conservatively assuming a 10 percent conversion of SO2 to H2SO4 and a molecular ratio of 1.53 from SO2 to H2SO4.

[e]VOC PTE is based on potential emissions from the Project's combustion sources only.

Note: PTE calculations are provided in a spreadsheet included in Attachment 3.

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 Osceola Power Project is not one of the 28 major source categories but does has a PTE greater than 250 tpy for at least one regulated pollutant. Additionally, the estimated emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project, exceed the PSD significant emissions levels of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, and PM/ PM_{10}, and SAM are subject to PSD review as a new major source. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the total project'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

A best available control technology (BACT) analysis for proposed Project has been included as an Attachment to this document.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants having a PTE greater than the PSD significant emission rate (i.e., NO_x, SO_2, CO, and PM/PM_{10}). (SAM emissions are discussed in the BACT, Section 3.0, but were not assessed in the application). 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 an air dispersion modeling protocol previously submitted to the FDEP (Attached).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA-approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. 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 to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing each SCCT unit's proposed operating load range (i.e., 60, 80, and 100 percent loads) with a worst-case set of stack parameters and pollutant emission rates conservatively selected from vendor performance data to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping."

The worst-case representative stack parameters and emission rates for each load, fuel type, and ambient temperature 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 3.

4.2.2 Land Use Dispersion Coefficient Determination

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

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. EPA's <u>Guideline for Determination of Good Engineering Practice Stack Height</u> 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 each SCCT is 41.55 m (136.3 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

Operating Scenario/Fuel	ISCST3 Source ID[a]	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
						NO_x	SO_2	CO	PM/PM_{10}[d]
SCCT Natural Gas and Distillate Fuel Oil	SWCBF	22.86	5.49	36.52	840.37	43.22	13.15	8.82	4.28
SCCT Annualized[b]	Annual	22.86	5.49	48.13	857.59	10.30	2.85	2.36	1.24
Diesel Fire Pump[d]	SFP	7.32	0.15	60.02	615.93	N/A	0.004	0.013	0.004
	AFP	7.32	0.15	60.02	615.93	0.009	0.0006	N/A	0.0006

[a]S or A refer to short-term or annualized emission rate; WC refers to worst case conditions; BF refers to both fuels (natural gas and distillate fuel oil).

[b]Annualized emission rate based on 1,000 hours of natural gas firing and 2,000 hours of distillate fuel oil firing.

[c]Assumes front and back half PM/PM_{10} Emissions.

[d]Assumes the diesel fire pump operates 52 hours per year for testing purposes.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1 km, 250 m spacing from 1 to 3 km, 500 m spacing from 3 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing of 50 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. 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

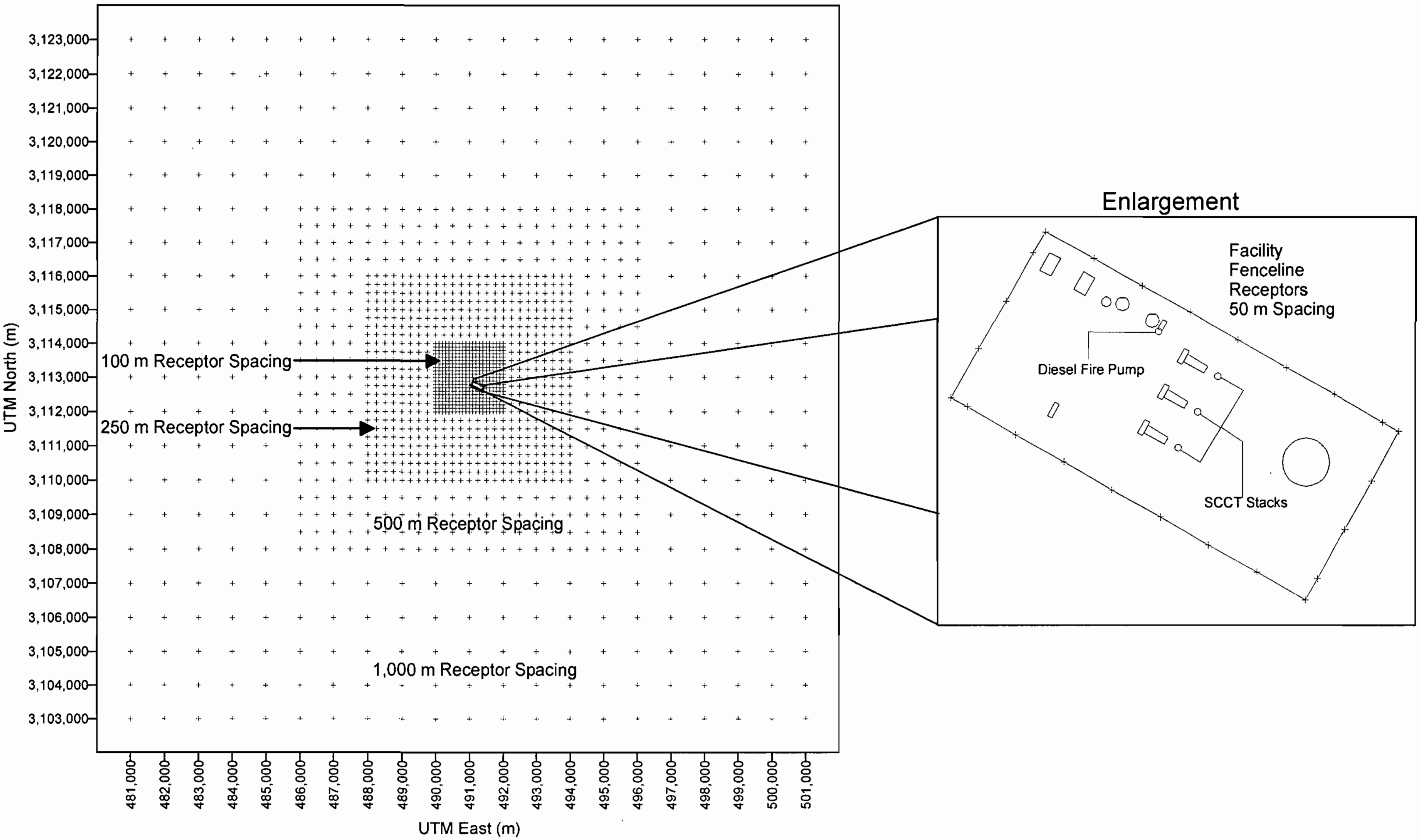
The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, Florida and Waycross, Georgia, 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 Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, 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, SO_2, CO, and PM/PM_{10} for each applicable averaging period. Tables 4-2 through 4-5 present the results for the 5 year refined modeling period (1984-1988) for each pollutant and applicable averaging period.

4.3.1 Comparison to PSD SILs and Pre-Construction Monitoring Requirements

Table 4-6 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the pre-construction monitoring requirements. As the Table indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for



Receptor and Emission Source Locations

Figure 4-1

Reliant Energy Osceola, L.L.C.
Osceola Power Project
Enveloped Stack Parameters

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Special Comments:

Load	100 Percent (Base) (NG)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	100 Percent Load	
Exit Velocity (ft/s)	163.05	157.91	151.95	151.95 ft/s	46.33 m/s
Exit Temperature (F)	1071.00	1111.00	1137.00	1071.00 F	850.37 K
Emissions (lb/h)					
NOx	73.50	70.00	65.33	73.50 lb/h	9.26 g/s
CO	36.20	33.80	31.50	36.20 lb/h	4.56 g/s
SO2	1.14	1.08	1.01	1.14 lb/h	0.14 g/s
PM[1]	18.00	18.00	18.00	18.00 lb/h	2.27 g/s

Load	80 Percent (NG)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	80 Percent Load	
Exit Velocity (ft/s)	138.11	134.55		134.55 ft/s	41.02 m/s
Exit Temperature (F)	1116.00	1145.00		1116.00 F	875.37 K
Emissions (lb/h)					
NOx	61.83	58.33		61.83 lb/h	7.79 g/s
CO	29.20	28.00		29.20 lb/h	3.68 g/s
SO2	0.96	0.90		0.96 lb/h	0.12 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for NG Across 3 Load	
119.79 ft/s	36.52 m/s
1071.00 F	850.37 K
73.50 lb/h	9.26 g/s
36.20 lb/h	4.56 g/s
1.14 lb/h	0.14 g/s
18.00 lb/h	2.27 g/s

Load	60 Percent (NG)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	60 Percent Load	
Exit Velocity (ft/s)	122.67	119.79		119.79 ft/s	36.52 m/s
Exit Temperature (F)	1153.00	1180.00		1153.00 F	895.93 K
Emissions (lb/h)					
NOx	52.50	49.00		52.50 lb/h	6.61 g/s
CO	25.70	24.50		25.70 lb/h	3.24 g/s
SO2	0.82	0.77		0.82 lb/h	0.10 g/s
PM[1]	18.00	18.00		18.00 lb/h	2.27 g/s

Representative Worst-Case Stack for both NG and FO Across 3 Loads	
119.79 ft/s	36.52 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	8.82 g/s
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load	100 Percent (Base) (FO)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	100 Percent Load	
Exit Velocity (ft/s)	168.22	161.59	155.03	155.03 ft/s	47.27 m/s
Exit Temperature (F)	1053.00	1084.00	1115.00	1053.00 F	840.37 K
Emissions (lb/h)					
NOx	343.00	323.00	300.00	343.00 lb/h	43.22 g/s
CO	70.00	65.00	61.00	70.00 lb/h	8.82 g/s
SO2	104.38	98.41	91.25	104.38 lb/h	13.15 g/s
PM[1]	34.00	34.00	34.00	34.00 lb/h	4.28 g/s

Load	80 Percent (FO)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	80 Percent Load	
Exit Velocity (ft/s)	139.85	136.01		136.01 ft/s	41.47 m/s
Exit Temperature (F)	1163.00	1175.00		1163.00 F	901.48 K
Emissions (lb/h)					
NOx	288.00	269.00		288.00 lb/h	36.29 g/s
CO	54.00	52.00		54.00 lb/h	6.80 g/s
SO2	88.10	82.57		88.10 lb/h	11.10 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

Representative Worst-Case Stack for FO Across 3 Load	
121.26 ft/s	36.97 m/s
1053.00 F	840.37 K
343.00 lb/h	43.22 g/s
70.00 lb/h	8.82 g/s
104.38 lb/h	13.15 g/s
34.00 lb/h	4.28 g/s

Load	60 Percent (FO)				
Turbine	PG7241(FA) - GE			Representative	
Ambient Temperature (F)	19	59	94	60 Percent Load	
Exit Velocity (ft/s)	124.01	121.26		121.26 ft/s	36.97 m/s
Exit Temperature (F)	1200.00	1200.00		1200.00 F	922.04 K
Emissions (lb/h)					
NOx	241.00	226.00		241.00 lb/h	30.37 g/s
CO	48.00	56.00		56.00 lb/h	7.06 g/s
SO2	74.44	69.83		74.44 lb/h	9.38 g/s
PM[1]	34.00	34.00		34.00 lb/h	4.28 g/s

[1] PM emissions are front and back half

Table 4-2
ISCST3 Model Predicted Maximum Concentration of SO_2

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
Annual	1987	0.03	1	491,211.5	3,112,867.0
	1988	0.03	1	491,211.5	3,112,867.0
	1989	0.03	1	491,211.5	3,112,867.0
	1990	0.03	1	491,211.5	3,112,867.0
	1991	0.03	1	491,211.5	3,112,867.0
24-Hour*	1987	1.51	5	491,211.5	3,112,867.0
	1988	1.27	5	491,211.5	3,112,867.0
	1989	1.54	5	491,211.5	3,112,867.0
	1990	1.53	5	491,211.5	3,112,867.0
	1991	1.50	5	491,211.5	3,112,867.0
3-Hour*	1987	5.92	25	491,211.5	3,112,867.0
	1988	4.88	25	491,211.5	3,112,867.0
	1989	5.47	25	491,211.5	3,112,867.0
	1990	4.84	25	491,211.5	3,112,867.0
	1991	4.96	25	491,211.5	3,112,867.0

* Values in table represent highest 2^{nd} highest concentration.

Table 4-3
ISCST3 Model Predicted Maximum Concentration of PM/PM_{10}

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
Annual	1987	0.03	1	491,211.5	3,112,867.0
	1988	0.03	1	491,211.5	3,112,867.0
	1989	0.03	1	491,211.5	3,112,867.0
	1990	0.03	1	491,211.5	3,112,867.0
	1991	0.03	1	491,211.5	3,112,867.0
24-Hour*	1987	1.51	5	491,211.5	3,112,867.0
	1988	1.27	5	491,211.5	3,112,867.0
	1989	1.53	5	491,211.5	3,112,867.0
	1990	1.52	5	491,211.5	3,112,867.0
	1991	1.50	5	491,211.5	3,112,867.0

* Values in table represent highest 2^{nd} highest concentration.

Table 4-4
ISCST3 Model Predicted Maximum Concentration of NO_x

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location East (m)	UTM Location North (m)
Annual	1987	0.39	1	491,211.5	3,112,867.0
	1988	0.38	1	491,211.5	3,112,867.0
	1989	0.51	1	491,211.5	3,112,867.0
	1990	0.41	1	491,211.5	3,112,867.0
	1991	0.52	1	491,211.5	3,112,867.0

Table 4-5
ISCST3 Model Predicted Maximum Concentration of CO

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class II SIL	UTM Location	
				East (m)	North (m)
8-Hour*	1987	8.80	500	491,211.5	3,112,867.0
	1988	8.99	500	491,211.5	3,112,867.0
	1989	9.01	500	491,211.5	3,112,867.0
	1990	11.61	500	491,211.5	3,112,867.0
	1991	9.97	500	491,211.5	3,112,867.0
1-Hour*	1987	32.65	2,000	491,211.5	3,112,867.0
	1988	31.25	2,000	491,211.5	3,112,867.0
	1989	32.64	2,000	491,211.5	3,112,867.0
	1990	30.46	2,000	491,211.5	3,112,867.0
	1991	31.79	2,000	491,211.5	3,112,867.0

* Values in table represent highest 2nd highest concentration.

Table 4-6
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	0.52	1	14
SO_2	Annual	0.03	1	-
	3-Hour	5.92	25	-
	24-Hour	1.54	5	13
CO	1-Hour	32.65	2,000	-
	8-Hour	11.61	500	575
PM/PM_{10}	Annual	0.03	1	-
	24-Hour	1.53	5	10

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

5.0 Additional and Class I Area Impact Analyses

The following sections discuss the Project's impacts on commercial, residential, and industrial growth, vegetation and soils, visibility, and nearby Class I areas.

5.1 Commercial, Residential, and Industrial Growth

The proposed Project is a new electrical power generating station to be constructed near Holopaw within Osceola County. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

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 Project will not have a significant effect upon the industrial growth in the immediate area considering that the generated electric power will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality impacts. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. The net number of new, permanent jobs that will be created by the Project 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.

5.2 Vegetation and Soils

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

The 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 that 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 impacts discussed in Section 4.0

showed that the NO_x, SO_2, CO, and PM/PM_{10} impacts are below the NAAQS. The impacts also are less than the much lower significant impact level thresholds. Because the Project's emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Project is located more than 150 km southeast of the Chassahowitzka National Wilderness Area (NWA), a Federal PSD Class I Area. The area is designated as mandatory Class I area, under the jurisdiction of the Fish and Wildlife Service as their Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and visibility/regional haze.

5.3.1 Class I Air Quality Impact Analysis and Results

Air dispersion modeling was performed to determine the Project's maximum predicted impact at the Class I area. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the NWA. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 4.0, were also used in the Class I air quality impact analyses.

Tables 5-1 through 5-4 presents the results of the Class I areas air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results in Table 5-4 indicate, the maximum predicted concentrations of all pollutants are less than the applicable Class I SILs for both annual and short-term averaging periods. Therefore, further analysis is not required.

Table 5-1
ISCST3 Model Predicted Maximum Concentrations of SO_2 at Chassahowitzka National Wilderness Area

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL[1] ($\mu g/m^3$)
Annual	1987	0.002	2	0.08
	1988	0.002	2	0.08
	1989	0.002	2	0.08
	1990	0.002	2	0.08
	1991	0.002	2	0.08
24-Hour*	1987	0.13	5	0.20
	1988	0.17	5	0.20
	1989	0.18	5	0.20
	1990	0.14	5	0.20
	1991	0.14	5	0.20
3-Hour*	1987	0.69	25	1.00
	1988	0.69	25	1.00
	1989	0.95	25	1.00
	1990	0.80	25	1.00
	1991	0.66	25	1.00

* Values in table represent highest 2nd highest concentration.
[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-2 ISCST3 Model Predicted Maximum Concentrations of PM/PM_{10} Chassahowitzka National Wilderness Area				
Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL[1] ($\mu g/m^3$)
Annual	1987	0.001	4	0.16
	1988	0.001	4	0.16
	1989	0.001	4	0.16
	1990	0.001	4	0.16
	1991	0.001	4	0.16
24-Hour*	1987	0.13	8	0.32
	1988	0.17	8	0.32
	1989	0.18	8	0.32
	1990	0.14	8	0.32
	1991	0.14	8	0.32

* Values in table represent highest 2^{nd} highest concentration.
[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-3
ISCST3 Model Predicted Maximum Concentrations of NO_x at Chassahowitzka National Wilderness Area

Averaging Period	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL[1] ($\mu g/m^3$)
Annual	1987	0.01	2.5	0.10
	1988	0.01	2.5	0.10
	1989	0.01	2.5	0.10
	1990	0.01	2.5	0.10
	1991	0.01	2.5	0.10

[1] Calculated as 4 percent of the PSD Class I Increment.

Table 5-4
Comparison of Maximum Predicted Impacts with the PSD Class I Significant Impact Levels at Chassahowitzka National Wilderness Area

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Level
SO_2	Annual	0.00	0.08
	24-Hour	0.18	0.20
	3-Hour	0.95	1.00
PM/PM_{10}	Annual	0.00	0.16
	24-Hour	0.18	0.32
NO_x	Annual	0.01	0.10

5.4 Visibility/Regional Haze Analysis

The Project is located more than 150 km southeast of the Chassahowitzka National Wilderness Area (NWA), the nearest Class I Area. Because of this great distance, and because the proposed Project will consist of highly efficient combustion turbines operating as peaking units and utilizing Best Available Control Technology to minimize emissions to the environment, a detailed visibility/regional haze analysis is not proposed.

Attachments

Attachment 1
(Turbine Vendor Data)

Reliant Energy/Osceola

ESTIMATED PERFORMANCE PG7241(FA)

Condition		BASE	80%	60%	BASE	BASE	80%	60%	BASE
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Evap. Cooler Status		Off	Off	Off	On	Off	Off	Off	On
Evap. Cooler Effectiveness	%				85				85
Fuel Type		Methane	Methane	Methane	Methane	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	130	130	130	130	80	80	80	80
Liquid Fuel H/C Ratio						1.8	1.8	1.8	1.8
Output	kW	171,200.	136,900.	102,700.	174,200.	181,800.	145,500.	109,100.	184,800.
Heat Rate (LHV)	Btu/kWh	9,350.	9,910.	11,280.	9,310.	9,950.	10,560.	11,910.	9,910.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.7	1,356.7	1,158.5	1,621.8	1,808.9	1,536.5	1,299.4	1,831.4
Exhaust Flow X 10^3	lb/h	3534.	2985.	2602.	3576.	3679.	2959.	2604.	3721.
Exhaust Temp.	Deg F.	1119.	1145.	1180.	1111.	1090.	1175.	1200.	1084.
Exhaust Heat (LHV) X 10^6	Btu/h	958.2	839.8	764.9	968.3	999.4	884.9	801.7	1011.8
Water Flow	lb/h	0.	0.	0.	0.	120,130.	96,430.	74,930.	119,510.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.	42.	42.	42.	42.
NOx AS NO2	lb/h	59.	50.	42.	60.	319.	269.	226.	323.
CO	ppmvd	9.	9.	9.	9.	20.	20.	24.	20.
CO	lb/h	29.	24.	21.	29.	65.	52.	56.	65.
UHC	ppmvw	7.	7.	7.	7.	7.	7.	7.	7.
UHC	lb/h	14.	12.	10.	14.	15.	12.	10.	15.
VOC	ppmvw	1.4	1.4	1.4	1.4	3.5	3.5	3.5	3.5
VOC	lb/h	2.8	2.4	2.	2.8	7.5	6.	5.	7.5
Particulates	lb/h	9.0	9.0	9.0	9.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.89	0.89	0.89	0.86	0.84	0.85	0.85
Nitrogen	74.36	74.37	74.45	74.19	71.35	71.26	71.81	71.25
Oxygen	12.33	12.37	12.61	12.28	11.06	10.65	11.17	11.04
Carbon Dioxide	3.84	3.82	3.71	3.84	5.60	5.87	5.61	5.60
Water	8.58	8.55	8.34	8.81	11.14	11.38	10.56	11.27

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 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.

Distillate 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.

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Reliant Energy/Escondido Power

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	80%	60%	BASE	83%	63%
Ambient Temp.	Deg F.	19.	19.	19.	19.	19.	19.
Fuel Type		Methane	Methane	Methane	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	21,515	18,300	18,300	18,300
Fuel Temperature	Deg F	130	130	130	80	80	80
Liquid Fuel H/C Ratio					1.8	1.8	1.8
Output	kW	187,000.	149,600.	112,200.	197,000.	157,600.	118,200.
Heat Rate (LHV)	Btu/kWh	9,140.	9,640.	10,930.	9,860.	10,400.	11,720.
Heat Cons. (LHV) X 10^6	Btu/h	1,709.2	1,442.1	1,226.3	1,942.4	1,639.5	1,385.2
Exhaust Flow X 10^3	lb/h	3791.	3118.	2707.	3951.	3059.	2657.
Exhaust Temp.	Deg F.	1071.	1116.	1153.	1053.	1163.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	1008.8	879.0	798.1	1064.5	931.4	843.7
Water Flow	lb/h	0.	0.	0.	131,670.	107,720.	84,490.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	42.	42.	42.
NOx AS NO2	lb/h	63.	53.	45.	343.	288.	241.
CO	ppmvd	9.	9.	9.	20.	20.	21.
CO	lb/h	31.	25.	22.	70.	54.	48.
UHC	ppmvw	7.	7.	7.	7.	7.	7.
UHC	lb/h	15.	12.	11.	16.	12.	10.
VOC	ppmvw	1.4	1.4	1.4	3.5	3.5	3.5
VOC	lb/h	3.	2.4	2.2	8.	6.	5.
Particulates	lb/h	9.0	9.0	9.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.90	0.88	0.87	0.86	0.86
Nitrogen	74.97	74.92	75.01	71.83	71.44	71.93
Oxygen	12.51	12.37	12.61	11.17	10.41	10.83
Carbon Dioxide	3.83	3.89	3.79	5.61	6.07	5.86
Water	7.79	7.92	7.71	10.53	11.23	10.52

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	60
Application		
Combustion System		9/42 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.

Distillate 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.

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Reliant Energy/Escondido Power

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	94.	94.	94.	94.
Evap. Cooler Status		On	Off	On	Off
Evap. Cooler Effectiveness	%	85		85	
Fuel Type		Methane	Methane	Dist.	Dist.
Fuel LHV	Btu/lb	21,515	21,515	18,300	18,300
Fuel Temperature	Deg F	130	130	80	130
Liquid Fuel H/C Ratio				1.8	1.8
Output	kW	158,600.	148,800.	168,300.	158,900.
Heat Rate (LHV)	Btu/kWh	9,570.	9,720.	10,090.	10,240.
Heat Cons. (LHV) X 10^6	Btu/h	1,517.8	1,446.3	1,698.1	1,627.1
Exhaust Flow X 10^3	lb/h	3353.	3235.	3474.	3354.
Exhaust Temp.	Deg F.	1137.	1151.	1115.	1128.
Exhaust Heat (LHV) X 10^6	Btu/h	921.2	885.7	958.1	921.8
Water Flow	lb/h	0.	0.	100,430.	99,680.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	42.	42.
NOx AS NO2	lb/h	56.	54.	300.	287.
CO	ppmvd	9.	9.	20.	20.
CO	lb/h	27.	26.	61.	59.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	13.	13.	14.	13.
VOC	ppmvw	1.4	1.4	3.5	3.5
VOC	lb/h	2.6	2.6	7.	6.5
Particulates	lb/h	9.0	9.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.87	0.85	0.85
Nitrogen	72.96	73.39	70.47	70.76
Oxygen	12.02	12.21	10.91	11.04
Carbon Dioxide	3.80	3.77	5.54	5.50
Water	10.35	9.76	12.24	11.85

SITE CONDITIONS

Elevation	ft.	91.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.0
Relative Humidity	%	44
Application		
Combustion System		9/42 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.

Distillate 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.

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Attachment 2
(Emission Calculation Spreadsheet)

Attachment 3
(TANKS 4.0 Output)

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

Identification

User Identification:	004
City:	Holopaw
State:	Florida
Company:	Reliant Energy Osceola, L.L.C.
Type of Tank:	Vertical Fixed Roof Tank
Description:	No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Tank Dimensions

Shell Height (ft):	32.00
Diameter (ft):	139.00
Liquid Height (ft):	28.00
Avg. Liquid Height (ft):	15.00
Volume (gallons):	3,000,000.00
Turnovers:	26.17
Net Throughput (gal/yr):	78,510,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

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

Roof Characteristics

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

Breather Vent Settings

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

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

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

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

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

Annual Emission Calculations	
Standing Losses (lb):	1,255.7299
Vapor Space Volume (cu ft):	402,646.0155
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9858
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	402,646.0155
Tank Diameter (ft):	139.0000
Vapor Space Outage (ft):	26.5341
Tank Shell Height (ft):	32.0000
Average Liquid Height (ft):	15.0000
Roof Outage (ft):	9.5341
Roof Outage (Dome Roof)	
Roof Outage (ft):	9.5341
Dome Radius (ft):	139.0000
Shell Radius (ft):	69.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance. (Shell):	0.1700
Tank Paint Solar Absorptance. (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9858
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	26.5341

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

Working Losses (lb):	2,494.6352
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	78,510,000.0000
Number of Turnovers:	26.1700
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	3,000,000.0000
Maximum Liquid Height (ft):	28.0000
Tank Diameter (ft):	139.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	3,750.3651

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	2,494.64	1,255.73	3,750.37

Attachment 4

(Best Available Control Technology)

Best Available Control Technology Analysis

The Reliant Energy Osceola, L.L.C.
Osceloa Power Project

Prepared for: Reliant Energy Osceola, L.L.C.

Prepared by: Black & Veatch

Executive Summary

A best available control technology (BACT) analysis was performed for three (3) new General Electric 7FA combustion turbines to be installed at Reliant Energy's Osceola Power Project. The combustion turbines are to be operated as simple cycle combustion turbines (SCCT), i.e., without heat recovery steam generators, to allow for fast response to changing system load demands. The following was evaluated to be BACT for the subsequent emissions parameters for each SCCT.

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

- Burning natural gas at unit loads between 60 percent and 100 percent of normal capacity, an emission limit of 10.5 ppmvd (referenced to 15 percent O_2).
- Burning fuel oil at load between 60 and 100 percent of normal capacity, an emission limit of 42 ppmvd (referenced to 15 percent O_2).

Carbon monoxide (CO) emissions--Good combustion controls to achieve a CO emission limit of 10.5 ppmvd during natural gas firing or 20 ppmvd during fuel oil firing.

Particulate emissions--Good combustion controls.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)--Good combustion controls using natural gas, and fuel oil with less than 0.05 percent sulfur.

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List of Tables

1.0 Introduction

The 1977 Clean Air Act 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 significant sources proposed for this project consist of three combustion turbines subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

2.0 BACT Analysis Basis

This section describes the basis of this BACT analysis. Information is provided on such issues as the project description, BACT methodology and approach used, and the parameters and factors used in developing the analysis are identified.

2.1 Project Description

The Osceola Power Project will consist of the installation of three General Electric 7FA combustion turbine electric generating units. Each combustion turbine unit will consist of one turbine and one generator operating as simple cycle combustion turbines (SCCT). The output rating for each of the new units will be nominally 170 MW net while firing gas. Total plant output will be nominally 510 MW.

The combustion turbines will fire natural gas and No. 2 fuel oil. The proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. This is equivalent to a per unit operation of 3,000 hours per year, with up to 2,000 hours per CT per year of fuel oil firing (up to 6,000 hours total). The balance of the facility's operation would consist of firing natural gas.

2.2 BACT Methodology

As defined in the air permit application, operation of the Project will result in an increase in the potential to emit emissions of NO_x, CO, PM/PM_{10}, and SO_2/Sulfuric Acid Mist (SAM); in excess of the major modification 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.

Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

2.3 Economic Basis

Table 2-1 lists the economic criteria used in the analysis of BACT alternatives.

Table 2-1
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	15
Real Interest Rate, percent	10
Economic Life years	20
Labor Cost, $/man-hr	50
Aqueous Ammonia Cost, $/ton (1999)	375
Energy Cost, $/kWhr (1999)	0.044
Catalyst Life, years	3

3.0 BACT Analysis Basis

The BACT analysis for the SCCT units is based on certain regulatory requirements and project assumptions.

The following is a summary of the requirements and assumptions for which this BACT analysis is based:

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal NSPS for combustion turbines with heat input greater than 10 MBtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for SO_2 and NO_x emissions only. No NSPS criteria have been established for limiting CO, VOC, and PM/PM_{10} emissions. The following flue gas emission limits are 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.
- The combustion turbine will have the following emission rates at 100% load and 59 °F:

	Natural gas	Fuel Oil
NO_x, ppmvd @ 15% O_2:	10.5	42
CO, ppmvd:	10.5	20
PM/PM_{10}, lb/hr:	18	34
SO_2, lb/hr	0.97	92.2
VOC, lb/hr	2.8	7.5

As mentioned previously, the proposed operating scenario for the combustion turbines consists of intermittent (peaking) operation up to 9,000 hours per year for the facility. This is equivalent to a per unit operation of 3,000 hours per year, with up to 2,000 hours per CT per year of fuel oil firing (up to 6,000 hours total). The balance of the facility's operation would consist of firing natural gas. For the purposes of this analysis, worst-case annual operation and emissions were evaluated. This is equivalent of 1,000 hours per year of natural gas firing and 2,000 hours per year of fuel oil firing per CT.

4.0 NO_x BACT

The objective of this analysis is to determine BACT for NO_x emissions from the combustion turbines. Unless otherwise noted the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents (CAPCOA, 1985-1992; USEPA, 1990 to present) indicates that the most stringent NO_x emissions limit for a natural gas fired CT is 3.0 ppmvd for the Sacramento Power Authority located in California. The emissions from that unit are controlled through the use of standard combustors and selective catalytic reduction (SCR). This unit is a combined cycle combustion turbine (CCCT) as compared to the simple cycle combustion turbine proposed for the Project. It should be noted that this combustion turbine 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 CCCT.

For SCCT units, the strictest emission limit identified during the review is 5 ppm. This limit has been set for three different projects in California. These projects are the Southern California Gas Wheeler Ridge Gas plant located in the San Joaquin Valley, the Carson Energy Project in metropolitan Sacramento, and the Sacramento Power Authority (Proctor and Gamble Plant) in metropolitan Sacramento.

It should also be noted that recently the South Coast Management District in California has officially declared new LAER limits for NO_x. This designation is limited to only specific application of CCCT projects and is not considered applicable to this Project as will be discussed.

Review of previous State of Florida DEP permits indicates that combustion turbine permits approved in the last 4 years have NO_x emission limits that vary from 15 to 9 ppmvd. The Oleander Power Project was recently granted a permit (Air Permit No. PSD-FL-258) during 1999 which limits NO_x emissions to 9 ppmvd when firing natural gas. Review of the permit conditions indicate that most of the NO_X generated by this facility will occur as a result of the fuel oil firing (at 42 ppmvd). Tampa Electric Company recently submitted a permit application for similar CTs that limit NO_x emissions to 10.5 ppmvd when firing natural gas, and 42 ppmvd during fuel oil firing. The primary fuel proposed for the Osceola Power Project will be based on economics and availability of the fuel.

4.2 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 zone is required to achieve stable combustion.

Nitrogen oxides control methods can 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 different types of emission controls reviewed by this BACT analysis are noted below.

- In Combustor Type Control:
  - Water/Steam Injection
  - Dry Low NO_x Burners
  - Xonon
- Post Combustion Type Control:
  - SNCR
  - SCR
  - SCONOX

4.2.1 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 dry low-NO_x burners has replaced the use of wet controls except for certain cases such as oil firing. The use of water injection will be considered for operations when firing oil.

4.2.2 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 dry low NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called dry low NO_x 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 system as the state of the art for NO_x controls in combustion turbine.

DLN combustion turbine burner designs are available that 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, while 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.

Also, as with the standard combustor with water injection, the dry low NO_x burners can also be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures can result in higher CO and VOC emissions if proper combustion control is not maintained. However, due to increased combustion efficiency associated with improved air/fuel mixing, emissions of CO and VOC also can be reduced through the proper use and control of DLN combustors.

4.2.3 XONON

Another form of in-combustor control is Xonon. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2700 °F at full power rating, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of carbon monoxide and unburned hydrocarbons when compared with conventional combustors. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce hot gases, which are used to drive the turbine. This technology is being commercialized by several joint ventures that Catlaytica has with turbine manufacturers. To date, commercial applications of this technology for utility size CTs, such as those proposed for this Project, have not been developed.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. This technology operates by injecting an ammonia or urea reagent into the exhaust gas, where it reacts with the NO_X to form water and molecular nitrogen. Reaction temperatures in the range of 1500 to 1900 °F, along with adequate reaction time at this temperature range, are required for this technology to be effective. However, the exhaust temperature at the exit of a combustion turbine, which ranges from 1,000 to over 1200 °F for the GE 7FA units, is too low for any consideration of this technology. SNCR is therefore not a viable control feasible option for this project

4.2.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CCCT projects for the past several years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. Ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, where the chemical conversion of NO_X to water and nitrogen takes place. The use of SCR results in small levels of ammonia emissions (ammonia slip) resulting from unreacted ammonia reagent passing through the catalyst bed and out the stack. Ammonia slip will increase over time as the catalyst degrades, ultimately requiring replacement of the catalyst.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas as it passes through the catalyst. Vanadia/titania 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 vanadia/titania catalyst is approximately 600 to 750 °F. At temperatures above 800 °F permanent damage to the vanadia/titania catalyst occurs. For the simple cycle turbines proposed for the Project, the flue gas temperature will typically range from 1050 to 1200 °F, which is well above the necessary reaction temperature window necessary for SCR operation. Accordingly, a vanadia/titania catalyst can not be installed at a simple cycle facility, and will not be evaluated further for this project.

However, a catalyst material developed from crystalline aluminasilicate compounds, known as zeolite, has been developed which has had mixed success in limited applications. This zeolite catalyst can operate effectively at temperatures of up to 1125 °F. Due to the high flue gas exit temperatures (up to 1200 °F) of the GE 7FA, the use of a zeolite catalyst would require special precautions and equipment additions. As previously indicated, the maximum operating temperature of the zeolite catalyst is 1125 °F. To prevent damage to the catalyst at these higher temperatures, a dilution air system and fan must be included for each unit to cool the flue gas below the maximum operating temperature of the catalyst. This BACT analysis will include a dilution air system in the evaluation of a zeolite catalyst based SCR.

Currently there is limited experience with the operation of zeolite catalysts in conjunction with units that fire sulfur bearing fuels, such as fuel oil. Operation of the SCR system on units that burn sulfur-bearing fuels can present a negative impact on the environmental performance of the combustion turbine through the formation of ammonia-sulfur salts. Reaction of excess ammonia that passes through the SCR with sulfur trioxide in the flue gas can form significant quantities of ammonia-sulfur salts, such as ammonium bisulfate. These compounds form when the flue gas cools upon leaving the stack, forming a fine particulate that significantly adds to the emission of PM_{10} from the unit. Increased PM_{10} emissions can lead to increased opacity from the unit, an increased contribution to regional haze, and additional health risks. Furthermore, an analysis of the SCR must consider reduced overall catalyst activity and higher catalyst deactivation rates due to sulfur poisoning of the catalyst encountered when firing fuel oil. In many cases, permitting authorities have recognized these negative impacts and provided permit exemptions for operating the SCR during fuel oil firing. Zeolite based catalysts are also significantly more expensive that vanadia/titania based catalysts used in combined cycle operation. The durability and effectiveness of zeolite catalysts in commercial SCR appliactions also has a limited operational history.

Because of the technical obstacles to effective use of SCR on simple cycle CTs firing fuel oil, this method of post-combustion control will be considered in this BACT analysis to control NO_x emissions when only firing natural gas.

4.2.6 SCONOX

A third, relatively new post-combustion technology is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO. Using this technology as a basis, the South Coast Management District recently declared LAER as 2.0 ppm of NO_x. However, because the $SCONO_x$ catalyst is sensitive to SO_2 and is required to operate in temperature range between 550 to 650 °F, this technology is not feasible for this Project because of the high exhaust temperatures and the use of fuel oil. Therefore, this method of post-combustion control will not be considered in this BACT analysis.

4.2.7 Technology Summary

The following control technologies will be evaluated in this NO_x BACT analysis and are ranked in order of relative control effectiveness:

- The addition of zeolite catalyst SCR systems to reduce outlet emissions from each combustion turbine to 5.0 and 42 ppmvd during natural gas and oil firing (LAER), respectively.

- In-combustor NO_x control consisting of dry low NO_x combustors to limit outlet emissions during natural gas firing to 10.5 ppmvd and water injection to limit outlet emissions to 42 ppmvd during fuel oil firing for all operating loads.

The NO_x emissions for a GE 7FA unit are summarized in Table 4-1. Note that NO_x emissions are provided for both 1,000 and 3,000 hours per year operation on natural gas, as well as 2,000 hours per year of fuel oil firing.

4.3 Evaluation of Feasible Technologies

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

4.3.1 Economic Impacts

The use of an SCR would have a significant economic impact on the Project. An analysis of the economic impact is provided in this section. Since control of NOx emissions during fuel oil firing has been rejected based on technical noncompatability issues, the BACT costs presented in this analysis are based on the worst-case scenario of operating the combustion turbines at full load for 3,000 hours per year on natural gas.

4.3.1.1 Capital and Operating Costs

Table 4-2 presents the capital costs for installing an SCR system on the General Electric 7FA combustion turbines to achieve a NO_x outlet emission level of 5.0 ppmvd (LAER) during natural gas firing and 42 ppmvd (LAER) for oil firing. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection systems; catalytic reactor; and balance of plant equipment. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the catalyst material were based on zeolite catalysts.

Table 4-3 presents the annual operating costs and emission rates using SCR to achieve NO_x outlet emissions of 5.0 and 42 ppmvd while firing natural gas and fuel oil, respectively. Annual operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements will require periodic replacement as they become deactivated. Currently, zeolite catalyst manufacturers will guarantee a catalyst life of three years of equivalent operating hours. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.40 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with the NO_2. The heat rate penalty cost item reflects the cost due to the SCR back pressure losses. The additional back pressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annual cost estimate.

The use of an SCR system also increases the energy requirements of the Project. The SCR system requires vaporizers and blowers to both vaporize and dilute the aqueous ammonia reagent for injection. These costs are inversely proportional to the controlled NO_X emissions rate - as emission rates go down, energy costs go up. Maintenance costs consist of routine SCR system maintenance, and replacement materials are assumed to be two percent of the original cost for equipment. Labor is assumed to be equal to materials.

Total 1999 annual costs for the NO_x control system are calculated as the sum of 1999 operating costs plus capital recovery factor. The total annual cost per unit for a 5.0 (gas)/42.0 (oil) ppmvd NO_x outlet emission SCR system for the 7FA combustion turbines is estimated to be $1,568,000. This annual cost results in a cost effectiveness per ton of NO_x removed of approximately $28,509.

Table 4-1
Estimated NO_x Emissions
From Alternate Control Technologies Per General Electric 7FA

Fuel	Control Technology Alternatives	
	Dry Low NO_x Combustors (Gas) - Water Injection (Oil)	SCR System
Natural Gas		
ppmvd (at 15% O_2)	10.5	5
Tons per year[a] – 1,000 hours operation	35	16.67
Tons per year[b] – 3,000 hours operation	105	50
Fuel Oil		
Ppmvd (at 15% O_2)	42	42[d]
Tons per year[c]	376.83	376.83
BACT Analysis (Annual)[e]		
Tons per year	411.83	393.5

Notes:

[a] Annual emissions are based on 1,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[b] Annual emissions are based on 3,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[c] Annual emissions are based on 2,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[d] SCR will not operate during fuel oil firing. BACT assumes worst-case NO_X emissions result from 3,000 hours per year of natural gas firing.

[e] BACT analysis total emissions are based on 1,000 hours per year of natural gas firing and 2,000 hours per year of No. 2 fuel oil firing.

Table 4-2
NO_x Control Alternative Capital Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts and Ammonia Injection	2,124,000	NA	Scaled from previous projects.
Catalyst Reactor	697,000	NA	Estimated from previous project.
Control/Instrumentation	140,000	NA	Estimated; includes controls and monitoring equipment.
Dilution Air System	Included	NA	Included with catalyst cost.
Ammonia Storage	218,000	NA	Scaled from previous projects
Balance of Plant	1,081,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering.
Total Direct Capital Cost	4,260,000	Base	
Indirect Capital Costs			
Contingency	639,000	NA	15% of Direct Capital Cost
Engineering and Supervision	426,000	NA	10% of Direct Capital Cost
Construction & Field Expense	213,000	NA	5% of Direct Capital Cost
Construction Fee	426,000	NA	10% of Direct Capital Cost,
Start-up Assistance	85,000	NA	2% of Direct Capital Cost
Performance Test	58,000	NA	Estimated Cost
Total Indirect Capital Costs	1,847,000	Base	
Total Installed Cost	**6,107,000**	Base	

Table 4-3

NO_x Control Alternative Annual Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	139,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	20,000	NA	See text for background information on this item
Reagent Feed	23,000	NA	Assumes 1.4 stoichiometric ratio
Power Consumption	121,000	NA	Includes dilution air fan
Lost Power Generation	167,000	NA	Back pressure on combustion turbine
Annual Distribution Check	21,000	NA	Required for SCR
Total Direct Annual Cost	491,000	NA	
Indirect Annual Costs			
Overhead	8,000	NA	60% of O&M Labor
Administrative Charges	122,000	NA	2% of Total Installed Cost
Property Taxes	168,000	NA	2.75% of Total Installed Cost
Insurance	61,000	NA	1% of Total Installed Cost
Capital Recovery	718,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	1,077,000	NA	
Total Annual Cost	**1,568,000**	NA	
Annual Emissions, tpy	50	105	Emissions from Table 4-1 for 3,000 hrs of natural gas firing
Emissions Reduction, tpy	55	NA	Emissions calculated from Table 4-1
Total Cost Effectiveness, $/ton	**28,509**	NA	Total Annual Cost/Emissions Reduction

4.3.1.2 Energy Impacts

The use of an SCR system impacts the energy requirements of the Project through its need for equipment to vaporize and dilute the aqueous ammonia reagent for injection into the flue gas stream. In addition, an SCR system catalyst will increase the back pressure on each combustion turbine by approximately 3.15 inches water gauge (in. w.g.). This increase in back pressure will reduce the output of each combustion turbine by approximately 0.44 percent. Increased power consumption and lost power generation are included in the annual cost estimate.

4.3.1.3 Environmental Impacts

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. With proper precautions, aqueous ammonia can be stored and used safely.

Some ammonia slip from the combustion turbine stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Also, the Ventura County California Air Pollution Control District recently set an ammonia slip emission limit of 10 ppmvd 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 more frequent catalyst replacement. A design value of 10 ppmvd is appropriate for a clean fuel facility such as this Project. 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.

Another consideration is the potential for formation of SO_3 and ammonia salts. When firing fuel oil or other sulfur-bearing fuels, the SCR catalyst will oxidize approximately 2 to 3% 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. Regardless, ammonium sulfate, bisulfate salts and sulfuric acid mist generated by the SCR will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than 10 microns in diameter (PM_{10}).

4.4 Conclusions

SCR systems are representative of the LAER level of NO_x emissions reduction. Although SCR systems have been successfully used on numerous combined cycle combustion turbine applications, there are only a limited number of SCCT applications, and these have yielded mixed results at best. The fundamental obstacle to the use of these systems on a SCCT is the overall economics and the potential primary (SO_2 to SO_3 oxidation) and secondary (ammonium bisulfate deposits and increased PM_{10} emissions) environmental impacts when sulfur-bearing fuels are fired

The overall annual cost of the SCR required to meet a NO_x emission limit of 5.0 ppmvd (natural gas firing) and 42.0 ppmvd (fuel oil firing) and calculated at $28,509 per ton is excessive. Furthermore, SCR use may result in significant 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. In addition, the potential for catalyst poisoning with sulfur bearing compounds during fuel oil firing severally affects the catalyst life on SCR systems. Therefore, based on energy, environmental, and economic impacts, the use of dry low NO_x combustors to meet an emissions limit of 10.5 ppmvd during natural gas firing, and water injection to meet an emission limit of 42 ppmvd during fuel oil firing, is recommended as BACT for the proposed General Electric 7FA combustion turbines at the Reliant Energy Osceola facility. The proposed limit is considered consistent with the range of emission limits allowed for other recent permits allowed in the U.S. and the State of Florida.

5.0 CO BACT

The objective of this analysis is to determine BACT for CO emissions from the combustion turbines.

5.1 BACT/LAER Clearinghouse Reviews

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. These emissions are achieved by reducing CO emissions through the use of an oxidation catalyst. It should be noted that the Newark Bay project represents LAER, which is located in an area designated as non-attainment areas for CO and ozone (VOC control required).

Recent applications in the State of Florida include the City of Tallahassee (25 ppm on gas and 90 ppm on oil), the FPC Hines project (25 ppm on gas and 30 ppm on oil), and the Tiger Bay project (15 ppm on gas and 30 ppm on oil).

5.2 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which can increase 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. Therefore, lowering combustion temperatures through steam/water injection or staged combustion, which is used to reduce combustor based NO_x formation, can be counterproductive with regard to CO emissions.

The only post-combustion 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, which is not considered to be toxic. No reagent injection is necessary, and oxidizing catalysts are capable of reducing CO emissions by as much as 90 percent. Because the CO emission rate of the 7FA machine is already low at 10.5 ppmvd during natural gas firing, any additional emission reduction would be limited to approximately 1.8 ppmvd at 15% O_2 (83 percent removal) if a catalyst is used. Reductions of up to 88 percent (to 2.4 ppmvd at 15% O_2) can be expected during periods of fuel oil firing. CO emissions for the control technology are estimated in Table 5-1.

5.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenario's evaluated.

5.3.1 Economic Impacts

The use of oxidation catalyst has a significant negative economic impact to the Project. Analysis of the economic impacts is provided below. Because CO emissions are higher when firing fuel oil than when firing natural gas (20 ppmvd versus 10.5 ppmvd, respectively), typical worst-case annual emissions would arise from the firing of the maximum amount fuel oil, with the balance of the firing on natural gas. The CO BACT costs presented in this analysis, therefore, are based on operating the General Electric 7FA unit at full load for 2,000 hours per year on No. 2 fuel oil, and 1,000 hours per year on natural gas.

5.3.1.1 Capital Costs

Tables 5-2 presents the capital costs for installing an oxidation catalyst system on a General Electric 7FA. The capital costs for the systems includes the oxidation catalytic reactor and balance of plant equipment, and were based on budgetary quotations from equipment manufacturers and other engineering estimates.

5.3.1.2 Operating Costs

Table 5-3 presents the annual operating costs and emission rates using an oxidation catalyst to achieve 83 and 88% reduction of CO on a General Electric 7FA unit firing natural gas and fuel oil, respectively. CO stack emissions would be reduced to a maximum of 1.8 ppmvd at 15 percent O_2 during natural gas firing and 2.4 ppmvd during fuel oil firing. Annual operating costs for each 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 will guarantee a catalyst life of three years of equivalent operating hours for an oxidation catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

Total 1999 annual cost for the oxidation catalyst system is calculated as the sum of the 1999 annual operating costs plus capital recovery. The total annual operating cost for an oxidation catalyst is estimated to be $892,000. This results in an incremental CO removal cost of $12,888.

5.3.1.3 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the back pressure on the combustion turbine. The additional back pressure of 3.15 inches (w.g.) will reduce the CT output by approximately 0.44 percent. The cost of lost power revenue due to the back pressure is included in the economic analysis.

5.3.1.4 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions from sources firing fuel oil is that a significant percentage of the SO_2 in the flue gas will oxidize to SO_3. Higher operating temperatures result in a higher SO_2 to SO_3 oxidation potential. With the high exhaust temperatures seen on SCCT units, it is estimated that between 75 to 90% of the SO_2 in the flue gas will be oxidized to SO_3 by the CO oxidation catalyst. The SO_3 will then react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Because these units will fire fuel oil, formation of SO_3 and H_2SO_4 is a substantial concern. These emissions may significantly increase PM_{10} emissions from this facility. This additional particulate matter will predominately consist of matter less than 10 microns in diameter (PM_{10}).

5.4 Conclusions

Installation of an oxidation catalyst system designed to reduce CO emissions by up to 88 percent would add approximately $892,000 to the annual operating capital cost of a GE 7FA. The resulting cost effectiveness on a per-ton of CO removed basis is $12,888/ton, which is an excessively high cost for this pollutant. CO catalysts have not typically been applied to similar applications under BACT consideration, and the proposed CO emission rate of 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing represent emission levels equal to, or lower than other recent projects permitted by the State.

Table 5-1
Estimated CO Emissions From
Alternate Control Technologies Per GE 7FA Unit

Fuel	Control Technologies	
	Dry Low NO_x Combustors	Oxidation Catalyst
Natural Gas		
Ppmvd	10.5	1.8 (83% Reduction)
Tons per year[a]	43.5	8.7
Fuel Oil		
Ppmvd	20	2.4 (88% Reduction)
Tons per year[b]	195	23.4
BACT Basis (Annual)[c]		
Tons per year	79.5	10.3

Notes:

[a] Annual emissions based on 1,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[b] Annual emissions are based on 2,000 hours of operation per year at full load rating with an ambient temperature of 59 °F.

[c] Annual emissions are based on firing natural gas for 1,000 hours and No. 2 fuel oil for 2,000 hours per year at full load rating with an ambient temperature of 59 °F.

Table 5-2
CO Reduction System Capital Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Catalysts	712,000	NA	Scaled from previous vendors quotes
Catalyst Reactor	697,000	NA	Calculated based on catalyst size
Dilution Air System	281,500	NA	Estimated for entire fan system
Control/Instrumentation	40,000	NA	Estimated
Balance of Plant	260,000	NA	For: 15% For Foundations & Supports, Erection, Electrical Installation, Painting, Insulation, Vendor Engineering.
Total Direct Capital Cost	1,991,000	Base	
Indirect Capital Costs			
Contingency	299,000	NA	15% of Direct Capital Cost
Engineering and Supervision	100,000	NA	5% of Direct Capital Cost
Construction & Field Expense	40,000	NA	2% of Direct Capital Cost
Construction Fee	20,000	NA	1% of Direct Capital Cost
Start-up Assistance	20,000	NA	1% of Direct Capital Cost
Performance Test	10,000	NA	0.5% of Direct Capital Cost
Total Indirect Capital Costs	489,000	Base	
Total Installed Cost	**2,480,000**	Base	

Table 5-3
CO Reduction System Annual Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Table 5-1
Catalyst Replacement	89,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	38,000	NA	2% of Capitol Cost
Power Consumption	110,000	NA	Includes back pressure on combustion turbine and dilution air fan energy consumption
Lost Power Generation	198,000	NA	
Total Direct Annual Cost	435,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	23,000	NA	60% of Operating and Maintenance Labor
Administrative Charges	50,000	NA	2% of Total Installed Cost
Property Taxes	68,000	NA	2.75% of Total Installed Cost
Insurance	25,000	NA	1% of Total Installed Cost
Capital Recovery	291,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	457,000	NA	
Total Annual Cost	**892,000**	NA	
Annual Emissions, tpy	10.3	79.5	Emissions taken from Table 5-1
Emissions Reduction, tpy	69.2	NA	Emissions calculated from Table 5-1
Total Cost Effectiveness, $/ton	**12,888**	NA	Total Annual Cost/Emissions Reduction

Therefore, based on economic, environmental and energy impacts, the proposed BACT for the control of CO emissions for this project is good combustion practices using advanced combustion control design. Emissions for the GE 7FA will be limited to 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

6.0 PM/PM_{10} Emissions Control

The emissions of particulate matter from the Project will be controlled by ensuring complete combustion of the fuel and by minimizing SO_2 to SO_3 oxidation. Natural gas, one of the fuels proposed for the proposed Project contains only trace quantities of non-combustible material. Also, the manufacturer's standard operating procedures include filtering the turbine air inlet air, which will contribute to lower emissions of particulate matter from these CTs.

The NSPS regulation for combustion turbines does not contain a particulate emission limit, and the BACT/LAER clearinghouse also does not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with recent 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 therefore proposed for this project. Particulate emissions (front half catch only) will be limited to 0.0055 lb/MBtu (9 lb/hr at full load) while firing natural gas and 0.0093 lb/MBtu (17 lb/hr at full load) while firing oil.

7.0 SO_2 BACT Analysis

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.05% sulfur. The selection of these fuels provide inherently low SO_2 emissions. No supplemental SO_2 emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies. In addition, other recent Florida projects have identified the use of natural gas and low sulfur fuel oil as BACT for SO_2. Therefore, the use of natural gas and low sulfur fuel oil is considered as BACT for this project.

8.0 Summary

The following is a summary of BACT for the combustion turbines and the associated emission rates.

- Nitrogen oxides (NO_x) emissions
  The use of dry low NO_x burners during natural gas firing to achieve an emission limit of 10.5 ppmvd at 15 % O_2.
  Water injection during fuel oil firing to achieve an emission limit of 42 ppmvd at 15% O_2.

- Carbon monoxide (CO) emissions
  Good combustion controls to achieve a CO emission limit of 10.5 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

- Particulate emissions
  Good combustion controls.

- Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)
  Good combustion controls.
  The use of natural gas and fuel oil with less than 0.05% sulfur.

Attachment 5
(Dispersion Modeling Protocol)

Ambient Air Quality Impact Analysis Workplan
For the
Reliant Energy Osceola, L.L.C.
Osceola Power Project

Prepared By
Black & Veatch

June 1999

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1.0 Introduction

Reliant Energy Osceola, L.L.C. proposes to install three (3) simple cycle combustion turbines (here-inafter referred to as the "project"), at a location near Holopaw, Florida. The combustion turbines will use fuel oil and natural gas as fuel. It is anticipated that the project will be a new major stationary source, thus, subject to the Prevention of Significant Deterioration (PSD) review program. This Ambient Air Quality Impact Analysis Workplan (Workplan) describes the air quality impact analysis methodology for obtaining a Construction Permit for the project. After the Florida Department of Environmental Protection (FDEP) review and approval, this Workplan will provide the basis of a mutually agreed upon procedure for the final ambient air quality impact analysis in support of the air construction permit application.

This Workplan describes site and source characteristics, determination of pollutants applicable to the air quality review, and the analytical procedures that will be used to conduct the ambient air quality impact analysis. The ambient air quality impact analysis includes a determination of compliance with the National Ambient Air Quality Standards (NAAQS), the Prevention of Significant Deterioration (PSD) increments, and an additional impact assessment.

2.0 Project Characterization

The following sections briefly characterize the combustion turbine project including a general description of the project, location, and emission units, as well as an overview of the local air quality status and New Source Review (NSR) applicability.

2.1 Project Description

Reliant Energy Osceola, L.L.C. proposes to install three combustion (170 MW each) that will fire fuel oil and natural gas. The project will supply additional power to the existing electric grid.

2.2 Project Location and Proximity to Mandatory Class I Areas

The project will be located near Holopaw, Florida within the county of Osceola. Specifically, the project will be located approximately 1 kilometer (km) northwest of Holopaw, Florida as shown in Figures 2-1. The nearest Mandatory Class I Area is Chassahowitzka Wilderness Area and is located more than 150 km west-northwest of the project site. Because of this extreme distance to the Class I area from the project site, an ambient air quality impact analysis and a regional haze analysis are not being proposed for this area.

2.3 Project Emissions

The project will consist of three simple cycle combustion turbines (SCCT). Representative manufacturer's data and engineering estimates will be used to characterize and quantify the potential to emit (PTE) of the project for determining PSD applicability and developing representative worst-case stack parameters and emission rates for the air dispersion modeling analysis as described in Section 3.0.

2.4 Local Air Quality Attainment/Nonattainment Status

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable NAAQS. Likewise, a given area is generally classified as nonattainment

Figure 2-1

Proposed Power Plant Project Location

for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS. A review of the air quality status in the region reveals that the project site near Holopaw, Florida is in attainment or unclassifiable for all pollutants.

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. As noted in Section 2.4, the project will be located in an attainment area with respect to all pollutants. As such, the PSD program will apply to the project, which is assumed to be a new major stationary source.

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 NAAQS 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 under Section 107 of the CAA for any criteria pollutant. The primary provisions of the PSD regulations require that new major stationary sources and major modifications to existing major stationary sources be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply BACT to minimize the project's emissions of air pollutants.

A new stationary source can be defined as a "major stationary source" if it is classified as any one of the listed major source categories which emits, or has the potential to emit, 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories. Because the project does not fall into one of the major source categories the 250 tpy threshold is applicable to the project. Because the project is likely to exceed the 250 tpy threshold for at least one regulated pollutant the project will be subject to PSD review. Once the project becomes applicable to PSD review, PSD applicability will then be determined on a pollutant by pollutant basis for the remaining pollutant by comparing the net emissions increase of each pollutant against the PSD significant emission rates (i.e., 40 tpy for NO_x, 40 tpy for SO_x, 25 tpy for TSP, 15 tpy for PM_{10}, 100 tpy for CO, and 40 tpy for VOCs). Each regulated pollutant with a PTE above the PSD significant emission rates will be subject to PSD review, including a BACT assessment, ambient air quality impact analysis, and an additional impact analysis.

3.0 Ambient Air Quality Impact Analysis

The following sections discuss the air dispersion modeling methodology and Ambient Air Quality Impact Analysis (AAQIA) that are proposed for those regulated pollutants which are determined to have a PTE greater than the PSD significant emission rate and thus subject to PSD review. The AAQIA will be conducted in accordance with USEPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon modeling methodology initiated by this Workplan.

3.1 Air Dispersion Modeling Methodology

The base elevation at the site location for the project is approximately 23 m (75 ft) above mean sea level (amsl). The site topography is essentially flat with no terrain elevation expected to exceed the proposed stack height of 60 to 90 feet above grade elevation. Since the terrain in the immediate vicinity of the project is flat. Site dispersion modeling receptors will be located in only simple terrain. As such, the Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model is proposed for the AAQIA.

The ISCST3 model is a USEPA 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 will be used in a refined mode (based on the worst-case operating scenarios and five years of representative meteorological data) to determine the maximum predicted impact concentrations for the AAQIA. The refined ISCST3 modeling methodology is discussed below.

3.1.1 Model Input and Source Parameters

The AAQIA will be based on the worst-case combination of operating parameters. Manufacturer's data will be used as inputs in the ISCST3 air dispersion model to determine the maximum predicted ground level concentrations from the project based on various operating loads, equipment scenarios, and ambient operating temperatures. This will be accomplished by representing each combustion turbine with various operating loads in the air dispersion modeling. In a process referred to as "enveloping", each load analyzed will be represented with a set of stack parameters and pollutant emission rates that will be conservatively selected to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperatures, lowest exit velocity, and highest emission rate) over three ambient temperature ranges that include a representative minimum and maximum, and average annual ambient temperatures. Enveloping allows multiple operating scenarios to be conservatively considered in an AAQIA, while keeping the actual air dispersion modeling runs to a minimum.

3.1.2 Refined Modeling

The worst-case combination of representative operating loads for the combustion turbine will be used in the refined ISCST3 modeling for the PSD AAQIA. Actual sequential hourly meteorological data will be used to predict concentrations of each pollutant for each applicable averaging period.

3.1.3 GEP and Building Downwash Evaluation

The buildings and structures including the combustion turbine housings of the project will be analyzed to determine the potential to influence the plume dispersion from the combustion turbine stacks. The USEPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document will be followed in this evaluation. Structure dimensions and relative locations will be entered into the USEPA'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. This same program will also determine a good engineering practice (GEP) stack height for each of the combustion turbine stacks.

3.1.4 Model Options

The following standard USEPA default regulatory modeling options will be invoked in the ISCST3 model:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature

gradient values.

- Calm processing option.
- Terrain elevations will be incorporated.

3.1.5 Receptor Grids and Terrain Considerations

The air dispersion modeling receptor locations will be 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 is proposed that will extend 10 km from the center of the project. The rectangular grid network will consists of 100 m spacing out to 1 km, 250 m spacing from 1 to 3 km, 500 m spacing from 3 to 5 km, and then 1,000 m spacing from 5 to 10 km. Receptor spacing at 50 m intervals will be used along the property line. The receptor grid will be extended as necessary to ensure that the significant impact area is defined, and a 100 m fine grid will be used around the maximum receptor points. Terrain at all receptors will be modeled at the stack-base elevation.

3.1.6 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. The most recent five years (1987-1991) of surface data from Orlando, Florida and upper air meteorological data from the Tampa Bay International Airport available on the EPA's Support Center for Regulatory Air Models Bulletin Board System (SCRAM BBS) is proposed for this analysis. The meteorological data will be processed using the USEPA PCRAMMET program into a format suitable for the ISCST3 dispersion model.

3.1.7 Land Use Dispersion Coefficients

The USEPA's land use method will be used to determine whether rural or urban dispersion coefficients will be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site is classified as rural or urban using the Auer land use classification method. If rural land use types account for more than 50 percent of the land use area within the 3 km radius, then the rural dispersion coefficient option should be used. Otherwise, the urban coefficients are used.

Based on visual inspection of the USGS 7.5-minute topographic map of the proposed site location, it is conservatively concluded that over 50 percent of the area surrounding the proposed project are rural. Accordingly, the rural dispersion modeling option will be used.

3.2 Model Predicted Impacts

Based on the air dispersion modeling methodology outlined in the previous sections, the maximum model predicted ground-level concentrations for the worst-case operating scenario associated with the project will be determined for each regulated pollutant that is subject to PSD review and for which a significant impact level exists. From the modeling results, the significant impact area, preconstruction monitoring requirements, and the need for a NAAQS and PSD increment consumption analyses will be determined.

3.2.1 PSD Class II Significant Impact Area

The predicted inputs for all PSD significant pollutants will be compared to the applicable PSD Class II significant impact levels (SILs) identified in Table 3-1. If the model predicted maximum concentrations are less than the PSD significant impact levels for all pollutants and applicable averaging periods, then no further air dispersion modeling analyses will be performed. However, if the predicted impact of one or more pollutants and applicable averaging periods are greater than the PSD significant impact levels, then a significant impact area will be determined and interactive source modeling will be performed for those pollutants. In this event, additional agency consultation will be requested and an inventory of PSD increment consuming sources and all nearby sources for the NAAQS analysis will be obtained and included as interactive sources in the AAQIA.

3.2.2 Determination of Preconstruction Monitoring Requirements

Ambient air quality data will be compared with the PSD significant monitoring concentrations. If examination of existing air quality data in the area shows that the existing ambient pollutant concentrations for each criteria pollutant are less than the applicable significant monitoring concentrations, then an exemption from pre-application monitoring will be requested for that pollutant.

Table 3-1 PSD Class II significant impact levels (SILs)		
SO_2	3-hour	25 $\mu g/m^3$
	24-hour	5 $\mu g/m^3$
	Annual	1 $\mu g/m^3$
PM	24-hour	5 $\mu g/m^3$
	Annual	1 $\mu g/m^3$
NO_x	Annual	1 $\mu g/m^3$
CO	1-hour	2000 $\mu g/m^3$
	8-hour	500 $\mu g/m^3$

If the existing air quality concentration for a given pollutant is equal to or greater than the applicable PSD significant monitoring concentration, then pre-application monitoring applicability will be determined by comparing the pollutant's maximum model predicted concentration from the project to the applicable PSD significant monitoring concentration. If the project's maximum model predicted concentration for that pollutant is less than the applicable PSD significant monitoring concentration, then an exemption from pre-application monitoring requirements will be requested for that pollutant.

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

3.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I or other relative designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Federal Land Manager (FLM) typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and regional haze/visibility. The nearest Class I area is more than 150 km from the proposed project location, so a Class I area impact analysis is not proposed.

3.4 Additional Impact Analysis

Federal PSD regulations require the preparation of an analysis of additional impacts due to construction and operation of a new major stationary source or major modification to an existing major source. The analysis considers impairment to visibility, soils, and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source.

3.4.1 Commercial, Residential, and Industrial Growth

Analysis is typically conducted to predict the amount of commercial, residential, and industrial growth may result from the operation of a proposed facility and the effect this growth may have on the ambient air quality. Because the project site will not be manned, the effects to ambient air quality due to growth associated with the project are expected to be insignificant.

3.4.2 Vegetation and Soils

An analysis will be performed to examine the project's predicted ambient air quality impacts on local soils and vegetation. The secondary NAAQS will serve as a basis for assessing the vegetation and soil impacts.

3.4.3 Visibility

Because the nearest Class I area is more than 150 km from the proposed project location, the effects on visibility from the project on the mandatory Class I areas will not be evaluated.

Reliant Energy Osceola, L.L.C.
Osceola Power Project

Construction Permit Application
July 1999

BLACK & VEATCH

I. Application Information

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Reliant Energy Osceola, L.L.C.	
2. Site Name : Reliant Energy Osceola	
3. Facility Identification Number :	[X] Unknown
4. Facility Location : Approximately 0.75 miles west of the intersection of U.S. 192 and U.S. 441 Street Address or Other Locator : City : Holopaw County : Osceola Zip Code : 34771	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : J. Christopher Allen
Title : Vice President

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Reliant Energy Osceola, L.L.C.
Street Address : P.O. Box 4455
City : Houston
State : TX Zip Code : 77210-4455

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (713)207-7441 Fax : (713)207-0840

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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 units.*

J. C. L. Allen Sr. 7.30.99

Signature Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 170 MW Simple Cycle Combustion Turbine	NA
002	Unit 2 - 170 MW Simple Cycle Combustion Turbine	NA
003	Unit 3 - 170 MW Simple Cycle Combustion Turbine	NA
004	No. 2 Fuel Oil Storage Tank (3,000,000 gal)	NA

Purpose of Application and Category

Category I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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 :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

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

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

Category II : All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

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

Current operation permit number(s) :

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

Application Processing Fee

Check one :

[X] Attached - Amount : $7500.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : Reliant Energy Osceola, L.L.C. proposes to construct three (3) 170 MW natural gas (NG) and No. 2 fuel (FO) fired simple cycle combustion turbines (SCCTs) at the new electrical generating facility located nea Holopaw, Florida. The proposed SCCTs will be used for peaking power.	
2. Projected or Actual Date of Commencement of Construction :	31-Dec-1999
3. Projected Date of Completion of Construction :	31-Dec-1999

Professional Engineer Certification

1. Professional Engineer Name : Donald Schultz, P.E. Registration Number : 30304	
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Corporation Street Address : 11401 Lamar Avenue City : Overland Park	State : KS Zip Code : 66211
3. Professional Engineer Telephone Numbers : Telephone : (913)458-2028	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 pollutant 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 [✓] 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 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.

D V Schultz — July 28, 1999

Signature — Date

(seal)

CERTIFICATE NO. 30306 STATE OF

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact : Name : Jason M. Goodwin, P.E. Title : Senior Engineer
2. Application Contact Mailing Address : Organization/Firm : Reliant Energy Wholesale Group Street Address : 12301 Kurland, P.O. Box 4455 City : Houston State : TX Zip Code : 77034
3. Application Contact Telephone Numbers : Telephone : (713)945-7167 Fax : (713)945-7598

Application Comment

II. Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

1. Facility UTM Coordinates : Zone : 17 East (km) : 491.36 North (km) : 3112.71			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 28 5 17 Longitude (DD/MM/SS) : 28 8 29			
3. Governmental Facility Code : 0	4. Facility Status Code : C	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) : 4911
7. Facility Comment :			

Facility Contact

1. Name and Title of Facility Contact : Jason M. Goodwin, P.E. Senior Engineer
2. Facility Contact Mailing Address : Organization/Firm : Reliant Energy Wholesale Group Street Address : 12301 Kurland City : Houston State : TX Zip Code : 77034
3. Facility Contact Telephone Numbers : Telephone : (713)945-7167 Fax : (713)945-7598

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment :	

B. FACILITY REGULATIONS

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General - Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceeds the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment D for facility applicable requirements.

B. FACILITY REGULATIONS

List of Applicable Regulations

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100 - 300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
NOX	A
CO	A
VOC	B
SO2	A
PM	A
PM10	A
PB	B
SAM	A

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Attachment A
2. Facility Plot Plan :	Attachment B
3. Process Flow Diagram(s) :	Attachment C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	NA
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applic	Attachment D

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Requir

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 1 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.
2. Control Device or Method Code : 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	31-Dec-1999
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : PG7241(FA)
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1942	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : 24 hours/day	 7 days/week

52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General
Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 1		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.281 North (km) : 3112.785		
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

<u>Segment Description and Rate :</u> Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 343.0000000 lb/hour	379.7500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 73.5 lb/h Fuel Oil = 343 lb/h Worst Casel Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 70.0000000 lb/hour	88.1000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 36.2 lb/h Fuel Oil = 70.0 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 104.3800000 lb/hour	104.9500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simply cycle operation: Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 104.38 lb/h (0.05% Sulfur) Worst case hours of operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code :	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 15.9800000 lb/hour	16.0700000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Reference Manufacturer's Data	Units
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 0.2 lb/h Fuel Oil = 15.98 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	42.00 ppm @ 15% O2
4. Equivalent Allowable Emissions :	343.00 lb/hour 343.00 tons/year
5. Method of Compliance :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 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 :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.80 % by weight
4. Equivalent Allowable Emissions :	lb/hour tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.	

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	
4. Equivalent Allowable Emissions : 34.00 lb/hour 34.00 tons/year	
5. Method of Compliance :	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.	

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

<u>Allowable Emissions</u> 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 :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s): NOX
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	
11. Alterntive Modes of Operation (Emissions Trading) :	

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 3

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 2 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 002 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

<u>Emissions Unit Control Equipment</u> 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	31-Dec-1999	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : PG7241(FA)
4. Generator Nameplate Rating :	170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	1942 mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : 24 hours/day	 7 days/week

52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General
Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 2		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.263 North (km) : 3112.753		
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
343.0000000 lb/hour 379.7500000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 73.5 lb/h
Fuel Oil = 343 lb/h

Worst Casel Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
70.0000000 lb/hour 88.1000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 36.2 lb/h
Fuel Oil = 70.0 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 104.3800000 lb/hour	104.9500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simply cycle operation: Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 104.38 lb/h (0.05% Sulfur) Worst case hours of operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code :	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 18 lb/h Fuel Oil = 34 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
15.9800000 lb/hour 16.0700000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 0.2 lb/h
Fuel Oil = 15.98 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	343.00	lb/hour	343.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 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 :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.		

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 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 :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 2

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 3 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 003 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The emission unit will be a GE PG7241 FA combustion turbine firing both natural gas or low sulfur distillate fuel oil.		

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing, dry low NOx burner technology is used to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent by weight) and the use of natural gas to control emissions of sulfur dioxide and sulfuric acid.	
2. Control Device or Method Code :	30

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used during fuel oil firing to limit NOx emissions by lowering the combustion temperature through the use of water injection.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	31-Dec-1999	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : PG7241(FA)
4. Generator Nameplate Rating :	170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	1942 mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : Fuel Specific Maximum Heat Input Rates: Natural Gas Firing @ 19F, 100% load = 1709.2 MBtu/hr (LHV) Fuel Oil Firing @ 19F, 100% load = 1,942.4 MBtu/hr (LHV)		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : 24 hours/day	 7 days/week

52 weeks/year	3,000 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.300 requires the following:
(1) General
Air emissions units must obtain an air construction permit prior to construction or modification. Construction permits shall not be issued to any emissions unit that would cause or contribute to a violation of the ambient air quality standards or exceed the appropriate baseline concentrations plus the appropriate maximum allowable increase.

(2) Permitting Requirements
The applicant shall provide the nature and amounts of emissions from the emissions unit and the location, design, construction and operation of the emissions unit.

This facility is a Title V source.
See Attachment G for facility applicability requirements.

List of Applicable Regulations

See Attachment G for unit specific applicable requirements.

40 CFR 60 Subpart GG

40 CFR 72

40 CFR 73

40 CFR 75

FAC 62-204

FAC 62-210

FAC 62-212.100-300

FAC 62-213.400

FAC 62-214

FAC 62-296.410

FAC 62-297

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : 3		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : NA - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	0	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	11.27	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 491.245 North (km) : 3112.721		
14. Emission Point Comment : Exit temperature and flow rate are for base load at 59F. Temp = 1111 F (NG) and 1084 F (FO) Flow = 2,409,770 acfm (NG) and 2,465,928 acfm (FO)		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning natural gas. It is requested that operation be limited to 3,000 hours per year.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.80	5. Maximum Annual Rate : 5,411.84
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.00	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 947	
10. Segment Comment : heat input / (fuel LHV x fuel density) =heat rate 1,709.2 MBtu/h x 23.8 ft^3/lb / 22,550 Btu/lb =1.80 Mscf/h 1.80 Mscf/h x 3,000 h/yr =5,412 Mscf/yr 22,550 Btu/lb / 23.8 ft^3/lb =947 Btu/scf (LHV)	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple cycle combustion turbine burning No. 2 distillate fuel oil. It is requested that this emission unit be limited to 2,000 hours of fuel oil firing per year.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 15.06	5. Maximum Annual Rate : 30,111.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 129	
10. Segment Comment : heat input x fuel density / fuel LHV =heat rate 1942.4 MBtu/h / (18,300 Btu/lb x 7.05 lb/gal) = 15,056 gal/h 15,056 gal/h x 2000 h/yr = 30.11 Mgal/yr 18,300 Btu/lb x 7.05 lb/gal = 129 MBtu/10^3 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			NS
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			NS
8 - SAM	030		EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
343.0000000 lb/hour 379.7500000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 73.5 lb/h
Fuel Oil = 343 lb/h

Worst Casel Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(73.5 lb/h x 1,000 h/yr + 343 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 379.75 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 70.0000000 lb/hour	88.1000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 36.2 lb/h Fuel Oil = 70.0 lb/h Worst Case Hours of Operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (36.2 lb/h x 1,000 h/yr + 70.0 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 88.1 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 104.3800000 lb/hour 104.9500000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor Units Reference Manufacturer's Data
7. Emissions Method Code : 0
8. Calculations of Emissions : Highest hourly emissions for simply cycle operation: Natural Gas = 1.14 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 104.38 lb/h (0.05% Sulfur) Worst case hours of operation: Natural Gas = 1,000 h/yr Fuel Oil = 2,000 h/yr Potential Annual Emissions: (1.14 lb/h x 1,000 h/yr + 104.38 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 104.95 ton/yr
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 34.0000000 lb/hour	43.0000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Units Reference Manufacturer's Data	
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
34.0000000 lb/hour 43.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code :

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 18 lb/h
Fuel Oil = 34 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(18 lb/h x 1,000 h/yr + 34 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 43.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **SAM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
15.9800000 lb/hour 16.0700000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units
Reference Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 0.2 lb/h
Fuel Oil = 15.98 lb/h

Worst Case Hours of Operation:
Natural Gas = 1,000 h/yr
Fuel Oil = 2,000 h/yr

Potential Annual Emissions:
(0.2 lb/h x 1,000 h/yr + 15.98 lb/h x 2,000 h/yr) / (2,000 lb/ton) = 16.1 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations are based on worst case manufacturer's data across all ambient temperatures and operating loads.

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.50	ppm @ 15% O2		
4. Equivalent Allowable Emissions :	73.50	lb/hour	110.25	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		42.00	ppm @ 15% O2	
4. Equivalent Allowable Emissions :	343.00	lb/hour	343.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for NOx considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppv @ 15% O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines NOTE: 75 ppm @ 15% O2 is based on the equation in 40 CFR 60.332(a)(1)		

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 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 :	36.20	lb/hour	54.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	70.00	lb/hour	70.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for CO considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	1.71	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SO2 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	104.38	lb/hour	104.38	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h SO2 emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

<u>Allowable Emissions</u> 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS Subpart GG, 40 CFR 60.334(b)		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines.		

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h PM emission rate considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 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 :	18.00	lb/hour	27.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER				
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	34.00	lb/hour	34.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for PM-10 considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 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 :	0.20	lb/hour	0.30	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for up to 3,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :				
4. Equivalent Allowable Emissions :	15.98	lb/hour	15.98	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for up to 2,000 h/yr. Maximum lb/h emission rate for SAM considering all ambient temperatures and operating loads.				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : RULE: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : Required as a condition of 40 CFR 75.10, Subpart B.	

Continuous Monitoring System Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure the water to fuel ratio as required under 40 CFR 60.334.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : During fuel oil firing, a CM will be used to measure fuel flow as required under 40 CFR 60.334.	

Continuous Monitoring System Continuous Monitor 4

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CM will be installed to measure either the O2 concentration or the CO2 concentration as required by 40 CFR 75.10, Subpart B.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM : C	SO2 : C	NO2 : C
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	
11. Alterntive Modes of Operation (Emissions Trading) :	

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

   [X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

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

   [X] 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.

Emissions Unit Information Section 4

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : No. 2 Fuel Oil Storage Tank (3,000,000 gal)		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (3,000,000 gallon capacity) is reported as an emission unit because it is subject to the reporting requirements of the New Source Performance Standards (NSPS) Subpart Kb. The tank is a vertical fixed roof design.		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Breathing Loss - No. 2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301020	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate : 3,000.00	5. Maximum Annual Rate : 3,000.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

<u>Segment Description and Rate :</u> Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Losses - No. 2 Fuel Oil Throughput	
2. Source Classification Code (SCC) : 40301021	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate : 13.09	5. Maximum Annual Rate : 78,514.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1832 MBtu/h) / (0.14 MBtu/gal) = 13,086 gal/h (6,000 h/yr) x (13,086 gal/h) = 78,514,286 gal/yr (78,514,286 gal/yr) / (3,000,000 gal) = 26.17 turnovers/yr	

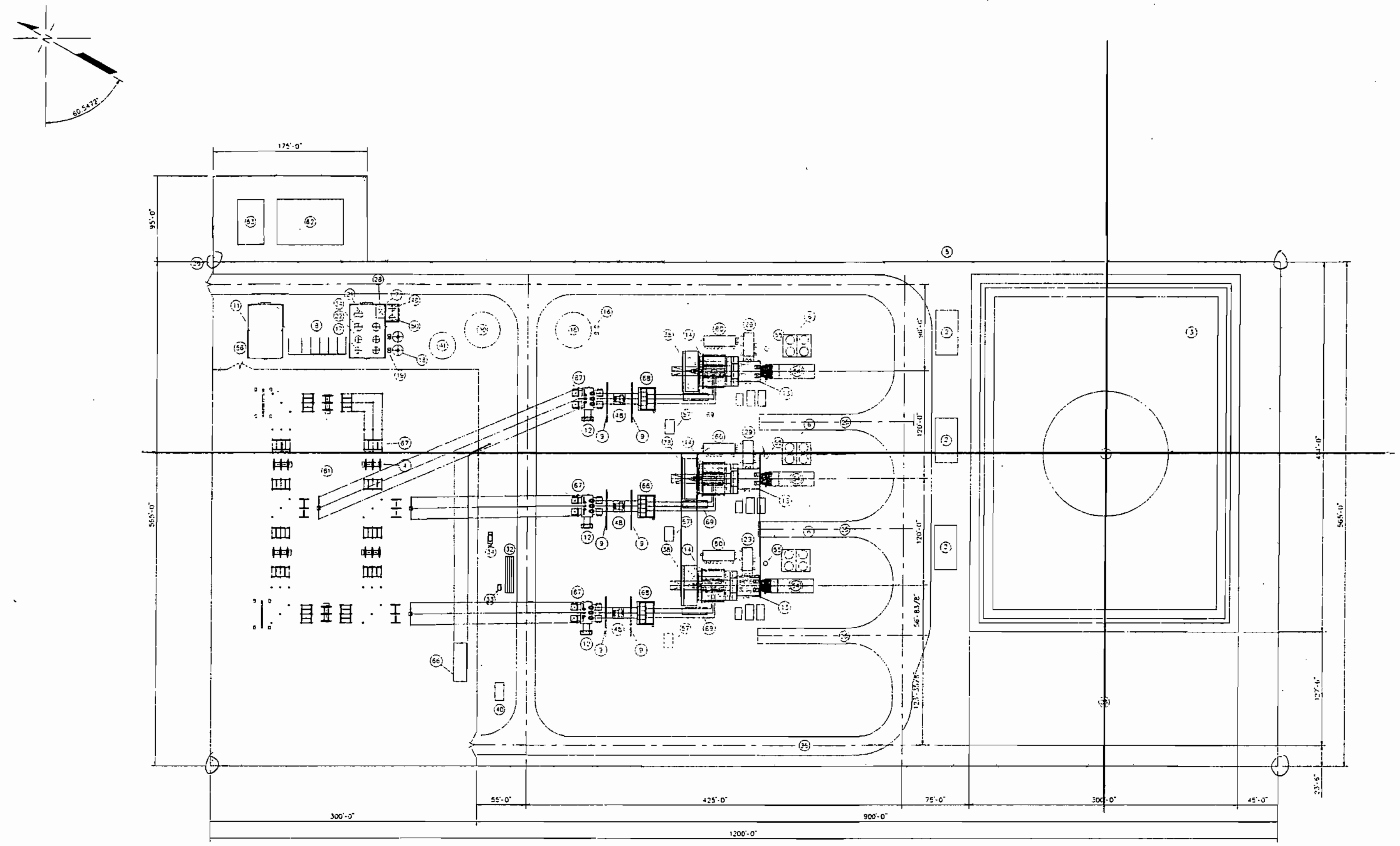
G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4
No. 2 Fuel Oil Storage Tank (3,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

Attachment B

Facility Plot Plan



LEGEND:

1 FUEL OIL STORAGE TANK
2. FUEL OIL OFF-LOADING
3. FUEL OIL CONTAINMENT BERM
4. 230KV CIRCUIT BREAKER
5 PERIMETER FENCE
6. COOLING MODULE
7. PRE-ENGINEERED WATER TREATMENT BLDG
8 EMPLOYEE PARKING
9 FIREWALL
10. DEMINERALIZED WATER STORAGE TANK
11. ELECTRICAL EQUIPMENT, OFFICE, PARTS STORAGE
12 STEP-UP TRANSFORMER
13 COMBUSTION GAS TURBINE GENERATOR
14. COMBUSTION GAS TURBINE
15. FIRE / RAW WATER TANK
16. FIREWATER PUMPS
17 ACID CATION EXCHANGERS
18. DECARBONATOR
19. DECARBONATOR FORWARDING PUMPS
20. NOT USED
21 DEMINERALIZER CONTROL PANEL
22. ANTON EXCHANGERS
23. NOT USED
24. MIXED BED EXCHANGERS
25. ROAD
26. LAYDOWN AREA
27. NOT USED
28. CHEMICAL FEED SKID
29 ACCESSORY MODULE
30 NOT USED
31. NOT USED
32. HYDROGEN TUBE TRAILER PARKING
33. HYDROGEN VALVE MANIFOLD
34 CO2 STORAGE
35. NOT USED
36 NOT USED
37. NOT USED
38. CT AIR INLET FILTER
39 NOT USED
40 OILY/WATER SEPARATOR
41. NEUTRALIZATION TANK
42. NOT USED
43 NOT USED
44 NOT USED
45 FUEL SKID
46 ACID TANK
47 NOT USED
48. AUXILIARY TRANSFORMER
49. ACID REGEN. SYSTEM
50 CAUSTIC TANK
51 CAUSTIC REGEN. SYSTEM
52. NOT USED
53 NOT USED
54. CT STACK
55 FUEL GAS FILTER SEPARATOR
56 GATE
57. MV SWITCHGEAR
58. NOT USED
59 NOT USED
60. CT ELECTRICAL PACKAGE
61. SWITHYARD
62. FUEL GAS SCRUBBER SKID
63 FUEL GAS METERING SKID
64. WATER WASH SKID
65. COMBUSTION TURBINE DRAIN TANK
66. SWITCHYARD CONTROL BUILDING
67. 230KV DISC. SWITCH
68. GENERATOR BREAKER
69 EXCITATION TRANSFORMER

NOT FOR EXTERNAL RELEASE
ISSUED FOR INTERNAL APPROVAL

BY ______________ DATE ________

BY ______________ DATE ________

PRELIMINARY

-50 -25 0 50 150 200 250 300

SCALE IN FEET

Reliant Energy. Wholesale Group

Escondido Project
Holopaw, Florida Site
Proposed Equipment Arrangement
3 & 3 Future -GE 7FAs Simple Cycle Installation

Rev	Date	Description	By	Checkd	Apprvd	Apprvd

Drawn by : J.G.Reyes Jr.	06-18-99	Scale :	1"=50'-0"
Checked by		Filename	904EPM05.DWG
Approved by		904-EP-M-05	
Approved by			

Attachment C

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 4

No. 2 Fuel Oil Storage Tank (3,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

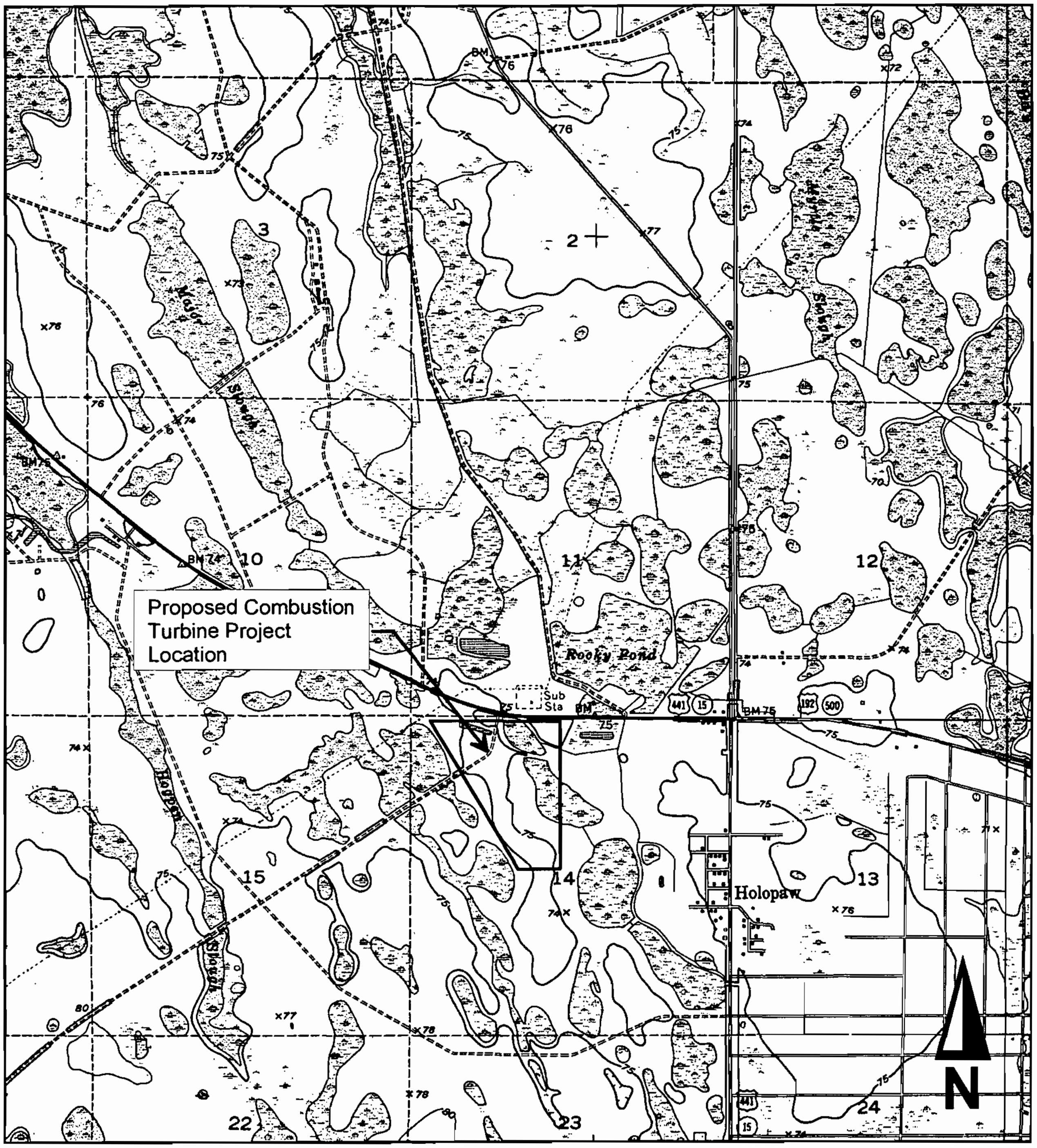
[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

Attachment A

Attachment A

Area Map Showing Facility Location



Base Map: 7.5' Quadrangle
Holopaw, Florida

Reliant Energy Osceola, L.L.C. Proposed Combustion Turbine Project Location

Figure 2-1

Attachment B

Attachment C

Process Flow Diagrams
(See individual unit process flow diagrams, Attachments H, and P)

Attachment D

Attachment D

Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement
40 CFR 60.7, Notification and recordkeeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable.
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.
40 CFR 60.8 (e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.

Applicable Regulation	Applicable Requirement
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with permit conditions.
	Permits, or a copy thereof, shall be kept at the work site of the permitted activity.
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.
F.A.C. 62-4.210, Construction	No person shall construct any installation or facility which

Applicable Regulation	Applicable Requirement
Permits	will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.
F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A. C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA.
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollution Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting form malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit an operating permit application by June 15, 1996.
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in emission of air pollutants shall take actions as required in

Applicable Regulation	Applicable Requirement
	F.A.C. 62-273.400, 62-273.500, and 62-273.600.
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.
F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air emergency, operations will be restricted as prescribed under 62-273.600.
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment E

Attachment E

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

As a result of the construction of the simple cycle combustion turbines and the associated equipment at the project site minimal quantities of unconfined particulate matter (fugitive dust) may be released tot he atmosphere. These anticipated construction activities might be generally broken down into three phases as they relate to generating fugitive dust: debris removal, site preparation, and general construction. Because the equipment are being installed at new facility, JEA proposes to utilize watering to control fugitive dust. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder maintaining soil moisture content or establishing a crust which prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. For the construction phase of the project, it is proposed that water be applied as necessary during high wind conditions when fugitive dust is evident beyond the property boundary. The water will be applied using on or a combination of several methods listed above.

Attachment F

Attachment F

Supplemental Information for Construction Permit Application

Supplemental Information for Construction Permit Application

Please refer to the Prevention of Significant Deterioration Air Permit Application for the Osceola Power Project.

Attachment G

Attachment G

Unit Specific Applicable Requirements

170 MW Simple Cycle Combustion Turbine
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).
40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined and recorded daily.
	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334(c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.

Applicable Regulations	Applicable Requirement
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibrations, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5(f).
40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system (NO_x pollutant monitor and an O_2 or CO_2 diluent gas monitor) with automated DAHS which records NO_x concentration, O_2 or CO_2 concentration, and NO_x emission rate.
	The owner or operator shall measure CO_2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted

Applicable Regulations	Applicable Requirement
	according to the procedures in Appendix F of this subpart.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.
40 CFR 75.11, Specific provisions for monitoring SO_2	Gas and oiled fired units shall measure and record SO_2 emissions as specified in 40 CFR 75, Appendix D.
40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO_2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20(b) and (c).
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.
	The owner or operator using the optional SO_2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20(g).
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24(c) through (e), and repeat tests applicable to the "out-of-control" parameter.
40 CFR 75.30, SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.
40 CFR 75.51, SUBPART F	The owner or operator shall comply with the recordkeeping

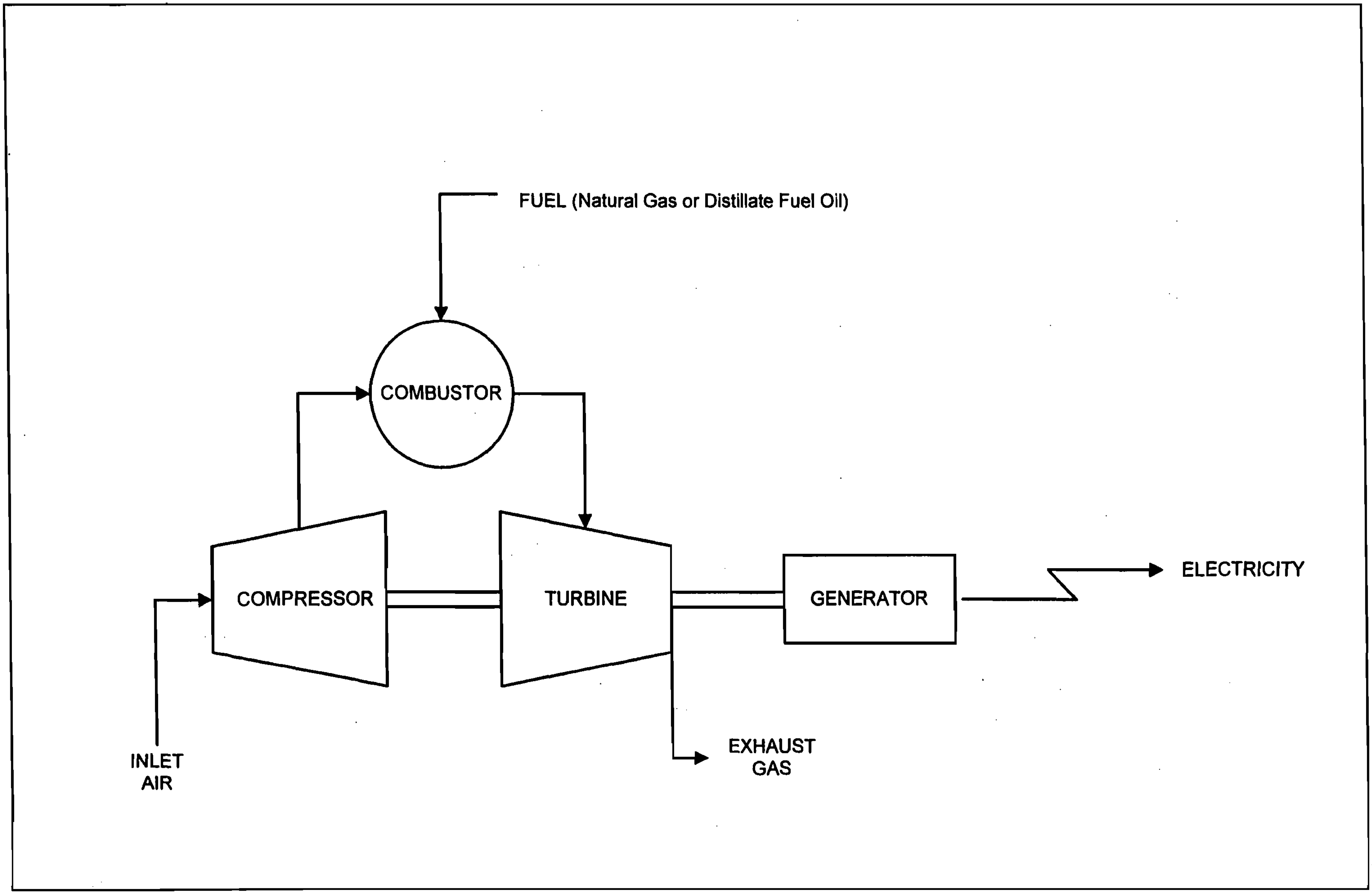
Applicable Regulations	Applicable Requirement
- Recordkeeping Requirements, General recordkeeping provisions for specific situations	requirements of 40 CFR 75.51(c)(1) through (3) when combusting natural gas and fuel oil.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52(a)(1) through (3) and 40 CFR 75.52(a)(5) through (7).
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO_2 emission records, the owner or operator shall record information as required in 40 CFR 75.55(c) in lieu of the provisions of 40 CFR 75.54(c).
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56(a)(1) through (3) and 40 CFR 75.56(a)(5) through (7).
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60(c) for any claims of confidential data.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this

Applicable Regulations	Applicable Requirement
	section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO_2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emissions rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment H

Attachment H

Process Flow Diagram



Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment I

Attachment I

Fuel Analysis or Specification

Fuel Analysis

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

Attachment J

Attachment J

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1.) Low NO_x Burner: A technology that 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.

2.) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

3.) Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Attachment K

Attachment K

Description of Stack Sampling Facilities

Stack Sampling Facilities

Vendors for these items have not yet been identified. A detailed description of the stack sampling facilities will be included with the operating permit application.

The stack sampling facilities will conform to F.A.C. Chapter 62-297.

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Chapter 62-297
Stationary Sources - Emissions Monitoring

Chapter 62-297
Stationary Sources - Emissions Monitoring

62-297.100 Purpose and Scope.
The Department of Environmental Protection adopts this chapter to establish test procedures that shall be used to determine the compliance of air pollutant emissions units with emission limiting standards specified in or established pursuant to any of the stationary source rules of the Department. Words and phrases used in this chapter, unless clearly indicated otherwise, are defined at Rule 62-210.200, F.A.C.
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(a); Formerly 17-297.100; Amended 11-23-94, 3-13-96.

62-297.200 Definitions. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.100; Amended 6-29-93; Formerly 17-297.200; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.310 General Compliance Test Requirements. The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air.

(1) Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard.

(2) Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined below. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

(a) Combustion Turbines. (Reserved)

(b) All Other Sources. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

(4) Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded Max. deviation between readings	Micrometer	+/-0.001" men of at least three readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(5) Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. inimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g). Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

(7) Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions

unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62- 210.300(4)(a)1. through 7., F.A.C.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

(8) Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.

2. The facility at which the emissions unit is located.

3. The owner or operator of the emissions unit.

4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.

11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

l2. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.

16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(b); Formerly 17-297.310; Amended 11-23-94, 3-13-96, 10-28-97.

62-297.330 Applicable Test Procedures. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92, Formerly 17-297.330; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.340 Frequency of Compliance Tests. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(2); Formerly 17-297.340; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.345 Stack Sampling Facilities Provided by the Owner of an Emissions Unit. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(4), Formerly 17-297.345, Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.350 Determination of Process Variables. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(5), Formerly 17-297.350, Amended 11-23-94. Repealed 3-13-96.

62-297.400 EPA Methods Adopted by Reference. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(c), Formerly 17-297.400, Amended 11-23-94, Repealed 1-1-96.

62-297.401 Compliance Test Methods.
This rule adopts the test methods to be used where a compliance test is required by Department air pollution rule or air permit. The EPA test methods and quality

assurance procedures listed in this rule and contained in 40 CFR Part 51, Appendix M, 40 CFR Part 60, Appendix A and F, 40 CFR Part 61, Appendix B and C and 40 CFR Part 63, Appendix A, are adopted and incorporated by reference in Rule 62-204.800, F.A.C. The EPA test methods that are adopted by reference in Rule 62-204.800, F.A.C., are adopted in their entirety except for those provisions referring to approval of alternative procedures by the Administrator. For purposes of this rule, such alternative procedures may only be approved by the Secretary or his or her designee in accordance with Rule 62-297.620, F.A.C.

(1)(a) EPA Method 1 -- Sample and Velocity Traverses for Stationary sources -- 40 CFR 60 Appendix A.

(b) EPA Method 1A -- Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts -- 40 CFR 60 Appendix A.

(2) EPA Method 2 -- Determination of Stack Gas Velocity and Volumetric Flow Rate -- 40 CFR 60 Appendix A.

(a) EPA Method 2A -- Direct Measurement of Gas Volume Through Pipes and Small Ducts -- 40 CFR 60 Appendix A.

(b) EPA Method 2B -- Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators -- 40 CFR 60 Appendix A.

(c) EPA Method 2C -- Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks and Ducts (Standard Pitot Tube) -- 40 CFR 60 Appendix A

(d) EPA Method 2D -- Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts -- 40 CFR 60 Appendix A.

(3) EPA Method 3 -- Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight -- 40 CFR 60 Appendix A.

(a) EPA Method 3A -- Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A

(b) (Reserved).

(4) EPA Method 4 -- Determination of Moisture Content in Stack Gases -- 40 CFR 60 Appendix A.

(5) EPA Method 5 -- Determination of Particulate Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 5A -- Determination of Particulate Emissions from the Asphalt Processing and Asphalt Roofing Industry -- 40 CFR 60 Appendix A.

(b) EPA Method 5B -- Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(c) Reserved.

(d) EPA Method 5D -- Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters -- 40 CFR 60 Appendix A.

(e) EPA Method 5E -- Determination of Particulate Emissions from the Wool Fiberglass Insulation Manufacturing Industry -- 40 CFR 60 Appendix A.

(f) EPA Method 5F -- Determination of Nonsulfate Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(g) EPA Method 5G -- Determination of Particulate Emissions from Wood Heaters from a Dilution Tunnel Sampling Location -- 40 CFR 60 Appendix A.

(h) EPA Method 5H -- Determination of Particulate Emissions from Wood Heaters from a Stack Location -- 40 CFR 60 Appendix A.

(6) EPA Method 6 -- Determination of Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 6A -- Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(b) EPA Method 6B -- Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(c) EPA Method 6C -- Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(7) EPA Method 7 -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 7A -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(b) EPA Method 7B -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry) -- 40 CFR 60 Appendix A.

(c) EPA Method 7C -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Colorimetric Method -- 40 CFR 60 Appendix A.

(d) EPA Method 7D -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(e) EPA Method 7E -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(8) EPA Method 8 -- Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(9)(a) EPA Method 9 -- Visual Determination of the Opacity of Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(b) Alternate Method 1 -- Determination of the Opacity of Emissions from Stationary Sources Remotely by Lidar -- 40 CFR 60 Appendix A.

(c) DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six- minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

(10) EPA Method 10 – Determination of Carbon Monoxide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 10A – Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries – 40 CFR 60 Appendix .

(b) EPA Method 10B – Determination of Carbon Monoxide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(11) EPA Method 11 – Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries – 40 CFR 60 Appendix A.

(12) EPA Method 12 – Determination of Inorganic Lead Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(13) EPA Methods 13A and 13B.

(a) EPA Method 13A – Determination of Total Fluoride Emissions from Stationary Sources – SPADNS — Zirconium Lake Method – 40 CFR 60 Appendix A.

(b) EPA Method 13B – Determination of Total Fluoride Emissions from Stationary Sources – Specific Ion Electrode Method – 40 CFR 60 Appendix A.

(14) EPA Method 14 – Determination of Fluoride Emissions from Potroom Roof Monitors of Primary Aluminum Plants – 40 CFR 60 Appendix A.

(15) EPA Method 15 – Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 15A – Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries – 40 CFR 60 Appendix A.

(16) EPA Method 16 – Semicontinuous Determination of Sulfur Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(a) EPA Method 16A – Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique) – 40 CFR 60 Appendix A.

(b) EPA Method 16B – Determination of Total Reduced Sulfur Emissions from Stationary Sources – 40 CFR 60 Appendix A.

(17) EPA Method 17 – Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method) – 40 CFR 60 Appendix A.

(18) EPA Method 18 – Measurement of Gaseous Organic Compound Emissions by Gas Chromatography – 40 CFR 60 Appendix A.

(19) EPA Method 19 – Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates – 40 CFR 60 Appendix A.

(20) EPA Method 20 – Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines – 40 CFR 60 Appendix A.

(21) EPA Method 21 – Determination of Volatile Organic Compound Leaks – 40 CFR 60 Appendix A.

(22) EPA Method 22 – Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares – 40 CFR 60 Appendix A.

(23) EPA Method 23 – Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources – 40 CFR 60 Appendix A.

(24) EPA Method 24 – Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings – 40 CFR 60 Appendix A.

(a) EPA Method 24A – Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings – 40 CFR 60 Appendix A.

(b) No change.

(25) EPA Method 25 – Determination of Total Gaseous Nonmethane Organic Emissions as Carbon – 40 CFR 60 Appendix A.

(a) EPA Method 25A – Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer – 40 CFR 60 Appendix A.

(b) EPA Method 25B -- Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer -- 40 CFR 60 Appendix A.

(26) EPA Method 26 -- Determination of Hydrogen Chloride Emissions From Stationary Sources -- 40 CFR 60, Appendix A.

(a) EPA Method 26A -- Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources - Isokinetic Method -- 40 CFR 60, Appendix A

(27) EPA Method 27 -- Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test -- 40 CFR 60 Appendix A.

(28) EPA Method 28 -- Certification and Auditing of Wood Heaters -- 40 CFR 60 Appendix A.

(a) EPA Method 28A -- Measurement of Air to Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances -- 40 CFR 60 Appendix A.

(29) EPA Method 29 -- Determination of Metals Emission from Stationary Sources -- 40 CFR 60 Appendix A.

(30) Reserved.

(31) 40 CFR 60 Appendix F -- Quality Assurance Procedures -- .

(32) EPA Method 101 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Air Streams -- 40 CFR 61 Appendix B.

(a) EPA Method 101A -- Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators -- 40 CFR 61 Appendix B.

(33) EPA Method 102 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Hydrogen Streams -- 40 CFR 61 Appendix B.

(34) EPA Method 103 -- Beryllium Screening Method -- 40 CFR 61 Appendix B.

(35) EPA Method 104 -- Determination of Beryllium Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(36) EPA Method 105 -- Determination of Mercury in Wastewater Treatment Plant Sewage Sludges -- 40 CFR 61 Appendix B.

(37) EPA Method 106 -- Determination of Vinyl Chloride Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(38) EPA Method 107 -- Determination of Vinyl Chloride Content of Inprocess Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin, Slurry, Wet Cake, and Latex Samples -- 40 CFR 61 Appendix B.

(a) EPA Method 107A -- Determination of Vinyl Chloride Content of Solvents, Resin-Solvent Solution, Polyvinyl Chloride Resin, Resin Slurry, Wet Resin, and Latex Samples -- 40 CFR 61 Appendix B.

(39) EPA Method 108 -- Determination of Particulate and Gaseous Arsenic Emissions -- 40 CFR 61 Appendix B.

(a) EPA Method 108A -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(b) EPA Method 108B -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(c) EPA Method 108C -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(40) 40 CFR 61 Appendix C -- Quality Assurance Procedures.

(41) EPA Method 201 -- Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure) -- 40 CFR 51 Appendix M.

(a) EPA Method 201A -- Determination of PM_{10} Emissions (Constant Sampling Rate Procedure) -- 40 CFR 51 Appendix M.

(42) EPA Method 202 -- Determination of Condensible Particulate Emissions from Stationary Sources -- 40 CFR 51 Appendix M.

(43) EPA Method 301 -- Field Data Validation Protocol -- 40 CFR Part 63, Appendix A.

(44) EPA Method 303 -- Coke Oven Door Emissions -- 40 CFR Part 63, Appendix A.
Specific Authority 403.061 FS.
Law Implemented 403.021, 403.031, 403.061, 403.087 FS.
History Formerly 17-2.700(6)(b), Amended 10-14-92, 6-29-93; Formerly 17-297.401; Amended 11-23-94, 1-1-96, 3-13-96, 10-7-96.

62-297.411 DEP Method 1. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)1, Formerly 17-297.411, Amended 11-23-94, Repealed 1-1-96.

62-297.412 DEP Method 2 (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)2, Formerly 17-297.412, Repealed 1-1-96.

62-297.413 DEP Method 3. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)3, Formerly 17-297.413, Repealed 1-1-96.

62-297.414 DEP Method 4. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)4, Formerly 17-297.414, Repealed 1-1-96.

62-297.415 DEP Method 5. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.a, Formerly 17-297.415; Amended 11-23-94, Repealed 1-1-96.

62-297.416 DEP Method 5A. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.b, Formerly 17-297.416, Repealed 1-1-96.

62-297.417 DEP Method 6. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)6, Formerly 17-297.417, Amended 11-23-94, Repealed 1-1-96.

62-297.418 DEP Method 7. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)7, Formerly 17-297.418, Repealed 1-1-96.

62-297.419 DEP Method 8. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)8, Formerly 17-297.419, Repealed 1-1-96.

62-297.420 DEP Method 9. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)9, Formerly 17-297.420, Amended 11-23-94, Repealed 3-13-96.

62-297.421 DEP Method 10. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)10, Formerly 17-297.421, Repealed 1-1-96.

62-297.422 DEP Method 11. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 62-2.700(6)(a)11, Formerly 17-297.422, Repealed 1-1-96.

62-297.423 EPA Method 12. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)12, Formerly 17-297.423, Amended 11-23-94, 1-1-96.

62-297.424 DEP Method 13. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)13, Formerly 17-297.424, Repealed 1-1-96.

62-297.440 Supplementary Test Procedures.
The following test procedures are adopted by reference. Copies of these documents are available from the emissions units set forth below. Copies may also be inspected at the Department's Tallahassee Office.

(1) ASTM Methods. Standard Methods published by the American Society for Testing and Materials are available from the Society at 1916 Race Street, Philadelphia, Pennsylvania 19103.

(a) ASTM D 322-67, 1972. Standard Method of Test for Dilution of Gasoline Engine Crankcase Oils.

(b) ASTM D 396-76. Standard Specification for Fuel Oils, superceding ASTM D 396-69.

(c) ASTM D 2880-76. Standard Specification for Gas Turbine Fuel Oils, superceding ASTM D 2880-71.

(d) ASTM D 975-77. Standard Specification for Diesel Fuel Oils, superceding ASTM D 975-68.

(e) ASTM D 323-72. Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method).

(f) ASTM D 97-66. Standard Test Method for Pour Point of Petroleum Oils.

(g) ASTM D 4057-88. Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(h) ASTM D 129-91. Standard Test Method for Sulfur in Petroleum Products (General Bomb Method).

(i) ASTM D 2622-94. Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry.

(j) ASTM D 4294-90. Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy.

(2) EPA Reports -- EPA occasionally publishes test methods and emission control guidelines in a report format. These documents are available (unless otherwise stated) from the National Technical Information Services, 5286 Port Royal Road, Springfield, Virginia 22216, and may be inspected at the Department's Tallahassee Office.

(a) Petroleum Liquid Storage.

1. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA 450/2-78-047, p. 5-3.

2. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed- Roof Tanks, EPA 450/2-77-036, p. 6-2.

(b) Gasoline Bulk Terminals.

1. Vapor Control System Test.

a. VOC emissions from the vapor control system shall be determined by the method given in Appendix A of EPA 450/2-77-026, except that an adequate sampling time shall be at least six (6) hours of operation. For continuous vapor processing systems at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test. For intermittent vapor processing systems, at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test and at least two full cycles of operation of the vapor processing system shall occur. This test shall be performed prior to the date of compliance and annually thereafter. Test results records shall be maintained at the terminal until the subsequent annual test shall be made available to the Department upon request.

b. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA 450/2-77-026, Appendix A. Emission Test Procedure for Tank Truck Gasoline Loading Terminals.

2. Vapor Leak Detection.

a. During loading or unloading operations at bulk terminals, there shall be no reading greater than or equal to 100 percent of the lower explosive level (LEL), measured as propane at 1 in. (2.5 centimeters) around the perimeter of a potential leak source as detected by a combustible gas detector using the procedure described in Appendix B of EPA 450/2-78-051.

b. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA 450/2-78-051, Appendix B, Gasoline Vapor Leak Detection Procedures by Combustible Gas Detector.

(c) Gasoline Service Stations.

1. Design Criteria for Stage I Vapor Control: Gasoline Service Stations, USEPA, OAQPS, ESED, November, 1975.

2. [Reserved]

(d) Non-destructive Control Devices.

1. Measurement of Volatile Organic Compounds, EPA 450/2-78-041, Attachment 3, Alternate Test for Direct Measurement of Total Gaseous Organic Compounds Using a Flame Ionization Analyzer.

2. [Reserved]

(e) Perchloroethylene Dry Cleaning Systems.

1. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA 450/2-78-050, p. 6-3, Compliance Procedures, Liquid Leakage.

2. RACT Compliance Guidance for Carbon Absorbers on Perchloroethylene Dry Cleaners. Task No. 119, Contract No. 68-01-4147. EPA, DSSE, May, 1980, pp. 8-21, Appendices A and B.

(f) Cross Recovery Determination. When determining if a kraft recovery furnace is a straight kraft or cross recovery furnace the procedure in 40 CFR 60.285(d)(3) of Subpart BB shall be used.

(3) American Conference of Governmental Industrial Hygienists, Recommended Practices -- Industrial Ventilation: A Manual of Recommended Practice. Equipment Specifications published in the 16th Edition of the Industrial Ventilation Manual (or any subsequent versions approved by the Department) are available from the American Conference of Governmental Industrial Hygienists, Committee on Industrial Ventilation, P. O. Box 16153, Lansing, Michigan 48901, and may be inspected at the Department's Tallahassee Office.

(4) American Petroleum Institute (API) Recommended Practices -- These are available from the API, 2101 L Street, Northwest, Washington, D. C. 20037

(a) API Standard 650, Welded Steel Tanks for Oil Storage, Sixth Edition, Revision 1, May 15, 1978.

(b) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February, 1980.

(c) API 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, September 1, 1977.

(5) Technical Association of the Pulp and Paper Industry (TAPPI), Test Methods -- These are available from TAPPI, P. O. Box 105113, Atlanta, Georgia 30348.

(a) TAPPI Method T.624, Analysis of Soda and Sulfate White and Green Liquors.

(b) (Reserved).

(6) Sulphur Development Institute of Canada (SUDIC) Sampling and Testing Sulphur Forms -- These are available from SUDIC, Box 950, Bow Valley Square 1, 830, 202-6 Avenue S. W., Calgary, Alberta T2P 2W6.

(a) S1-77. Collection of a Gross Sample of Sulphur.

(b) S2-77. Sieve Analysis of Sulphur Forms, except paragraph 4.3 concerning wet sieving is not adopted.

(c) S3-77. Determination of Material Finer than No. 50 (300um) Sieve in Sulphur Forms by Washing.

(d) S5-77. Determination of Friability of Sulfur Forms.

(7) EPA VOC Capture Efficiency Test Procedures. Adopted by reference is an EPA memo dated April 16, 1990 entitled, "Guidelines for Developing a State Protocol for the Measurement of Capture Efficiency." A copy can be obtained by writing to: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(a) Procedure F.1 -- Fugitive VOC Emissions from Temporary Enclosures.

(b) Procedure F.2 -- Fugitive VOC Emissions from Building Enclosures.

(c) Procedure G.1 -- Captured VOC Emissions.

(d) Procedure G.2 -- Captured VOC Emissions (dilution technique).

(e) Procedure L -- VOC in Liquid Input Stream.

(f) Procedure T -- Criteria for and Verification of Permanent or Temporary Total Enclosure.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(c); Amended 6-29-93, Formerly 17-297.440, Amended 11-23-94, 1-1-96.

62-297.450 EPA VOC Capture Efficiency Test Procedures.

(1) Applicability. The requirements set forth in Rules 62-297.450(2) and (3), F.A.C., shall apply to all regulated VOC emitting emissions units employing a control system pursuant to Rules 62-296.501 through 62-296.516, F.A.C., and Rule 62-296.800, F.A.C., except as provided in Rules 62-297.450(1)(a) and (b), F.A.C.

(a) If an owner or operator installs a Permanent Total Enclosure that meets the specifications of Procedure T, and which directs all VOC to a control device, the capture efficiency is assumed to be 100 percent, and the facility owner or operator is exempted from the requirements described in Rule 62-297.450(2) , F.A.C. This does not exempt the owner or operator from conducting any required control device efficiency test.

(b) If the owner or operator of an affected activity, process, or emissions unit uses a nondestructive control device designed to collect and recover VOC (e.g. carbon adsorber), an explicit measurement of capture efficiency is not necessary if the owner or operator is able to equate solvent usage with solvent recovery on a 24-hour (daily) basis, rather than a 30-day weighted average, and can determine this within 72 hours following each 24-hour period, and one of the following two criteria is also met:

1. The solvent recovery system (i.e., capture and control system) is dedicated to a single activity, process line, or emissions unit (e.g., one process line venting to a carbon adsorber system), or

2. The solvent recovery system controls multiple activities, process lines, or emissions units and the owner or operator is able to demonstrate that the overall control (i.e., the total recovered solvent VOC divided by the sum of liquid VOC input to all activities, process lines, or emissions units venting of the control system) meets or exceeds the most stringent emission standard applicable for any activity, process line, or emissions unit venting to the control system.

(c) If the conditions given above in Rule 62-297.450(1)(b), F.A.C., are met, the overall emission reduction efficiency of the system can be determined by dividing the recovered liquid VOC by the input liquid VOC. The general procedure for this determination is given in 40 CFR 60.433, which is adopted by reference.

(2) Specific Requirements. The capture efficiency of a capture system shall be determined using one of the following EPA procedures, or an alternate capture efficiency test procedure if approved by the Department under the provisions of Rule 62-297.620, F.A.C.

(a) Gas/gas method using a Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = Gw/(Gw + Fw)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)

Gw = mass of VOC captured and delivered to control device using a Temporary Total Enclosure

Fw = mass of fugitive VOC that escapes from a Temporary Total Enclosure
Procedure G.1 or Procedure G.2 is used to obtain Gw. Procedure F.1 is used to obtain Fw.

(b) Liquid/gas method using Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

CE = (L-F)/L

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F = mass of fugitive VOC that escapes from a Temporary Total Enclosure
Procedure L is used to obtain L. Procedure F.1 is used to obtain F.

(c) Gas/gas method using the building or room in which the affected activity, process, or emissions unit is located as the enclosure and in which G and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room must be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

CE = G/(G + F sub B)

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
G = mass of VOC captured and delivered to a control device
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure G.1 or Procedure G.2 is used to obtain G. Procedure F.2 is used to obtain F_B.

(d) Liquid/gas method using the building or room in which the affected activity, process, or emissions unit located as the enclosure and in which L and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room shall be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

CE = $(L-F_B)/L$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure L is used to obtain L. Procedure F.2 is used to obtain F sub B.

(3) Sampling Requirements. A capture efficiency test shall consist of at least three sampling runs. Each run shall cover at least one complete production cycle, but shall be at least 3 hours long. The sampling time for each run need not exceed 8 hours, even if the production cycle has not been completed.

(4) Recordkeeping and Reporting.

(a) The owner or operator of an affected activity, process, or emissions unit shall submit to the Department a list of the procedures that will be used for the capture efficiency tests at the owner or operator's facility. A copy of the list shall be kept on file at the affected facility.

(b) Required test reports shall be submitted to the Department within forty-five (45) days of the test date. A copy of the results shall be kept on file at the facility.

(c) If any physical or operational change is made to a control system, the owner or operator of the affected facility shall notify the Department of the change within ten (10) working days after making such change. The Department shall require the owner or operator of the affected activity, process, or emissions unit to conduct a new capture efficiency test if the Department has reason to believe (based on engineering calculations or empirical evidence) that a physical or operational change made to the capture system has decreased the overall emissions reduction efficiency of the system.

(d) Notwithstanding the provisions of Rule 62-297.340(1), F.A.C., the owner or operator of an affected activity, process, or emissions unit shall notify the Department thirty (30) days prior to performing any capture efficiency and/or control efficiency tests.

(e) The owner or operator of an affected activity, process, or emissions unit using a Permanent Total Enclosure shall demonstrate that this enclosure meets the requirement given in Procedure T for a Permanent Total Enclosure during any required control device efficiency test.

(f) The owner or operator of an affected activity, process, or emissions unit using a Temporary Total Enclosure shall demonstrate that this enclosure meets the requirements given in Procedure T for a Temporary Total Enclosure during any required control device efficiency test.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(7); Amended 6-29-93, Formerly 17-297.450, Amended 11-23-94, 1-1-96.

62-297.500 Continuous Emission Monitoring Requirements. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92; 6-29-93; Formerly 17-297.500; Repealed 11-23-94.

62-297.520 EPA Continuous Monitor Performance Specifications.
This rule adopts the continuous monitor performance specifications to be used where required by Department air pollution rule or air permit. The EPA performance specifications listed in this rule and contained in 40 CFR 60, Appendix B, are adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(4) Performance Specification 4--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(5) Performance Specification 4A--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(6) Performance Specification 5--Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources.

(7) Performance Specification 6--Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources.

(8) Performance Specification 7--Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: New 6-29-93, Formerly 17-297.520, Amended 11-23-94, 3-13-96.

62-297.570 Test Reports. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(8), Formerly 17-297.570, Amended 11-23-94, Repealed 3-13-96.

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

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.

Attachment L

Attachment L

Compliance Test Report

Compliance Test Report

A compliance test report will be included with the operating permit application after construction and initial testing has been completed.

Attachment M

Attachment M

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

As a normal start up is initiated, the date and time is documented when the turbine starts firing. Turbine start up continues with a normal warm up. The date and time is documented again when the generator breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NO_x emissions are controlled and stable, the date and time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Attachment N

Attachment N

Operation and Maintenance Plan

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by the construction permit.

Attachment O

Attachment O

Unit Specific Applicable Requirements

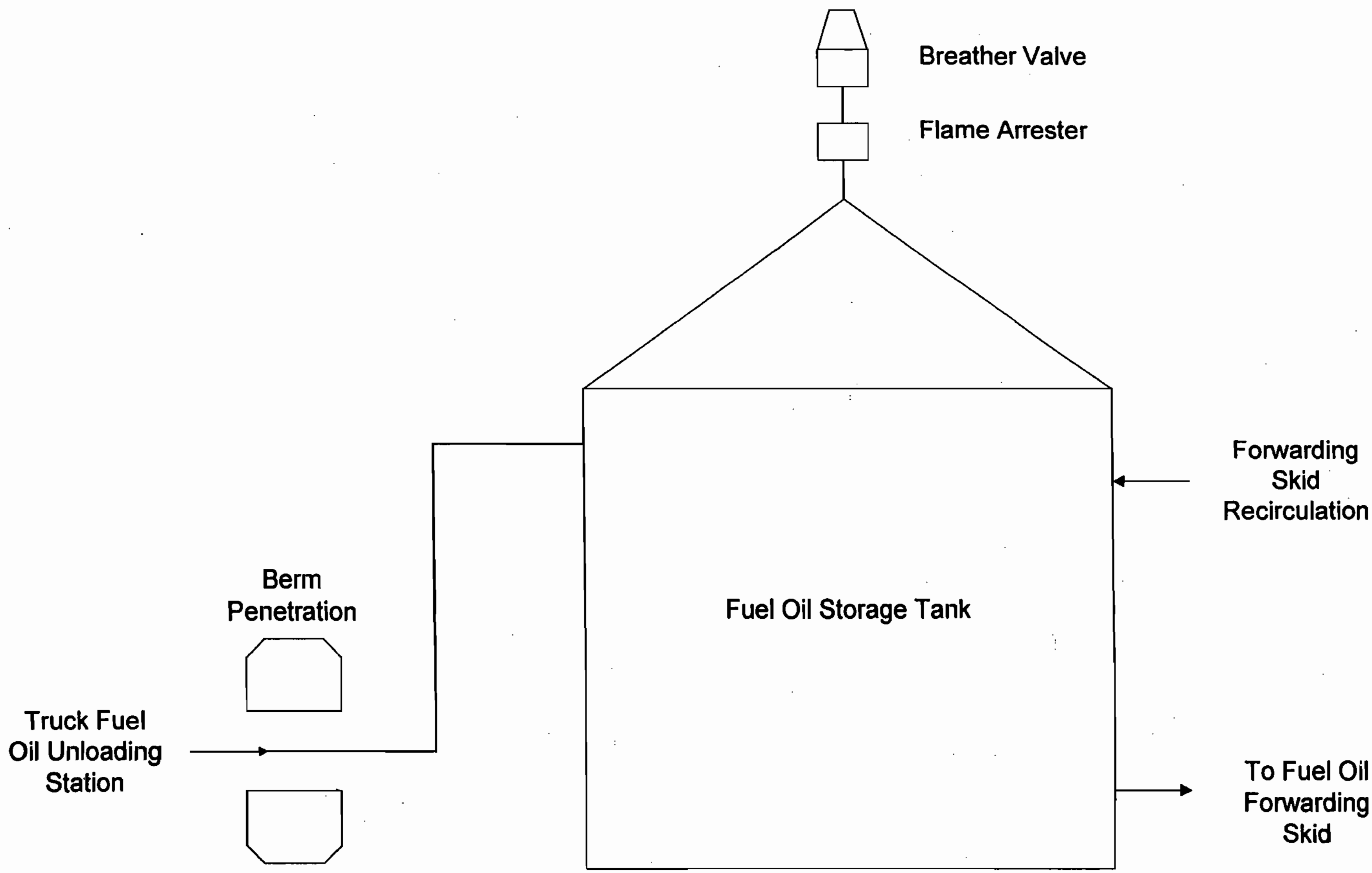
3,000,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of Operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment P

Attachment P

Process Flow Diagram


Breather Valve
Flame Arrester
Forwarding Skid Recirculation
Berm Penetration
Fuel Oil Storage Tank
Truck Fuel Oil Unloading Station
To Fuel Oil Forwarding Skid

Attachment Q

Attachment Q

Emission Source Calculations

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

Identification	
User Identification:	004
City:	Holopaw
State:	Florida
Company:	Reliant Energy Osceola, L.L.C.
Type of Tank:	Vertical Fixed Roof Tank
Description:	No. 2 Fuel Oil Storage Tank (3,000,000 gal)
Tank Dimensions	
Shell Height (ft):	32.00
Diameter (ft):	139.00
Liquid Height (ft):	28.00
Avg. Liquid Height (ft):	15.00
Volume (gallons):	3,000,000.00
Turnovers:	26.17
Net Throughput (gal/yr):	78,510,000.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	0.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

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

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

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

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

Annual Emission Calculations	
Standing Losses (lb):	1,255.7299
Vapor Space Volume (cu ft):	402,646.0155
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9858
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	402,646.0155
Tank Diameter (ft):	139.0000
Vapor Space Outage (ft):	26.5341
Tank Shell Height (ft):	32.0000
Average Liquid Height (ft):	15.0000
Roof Outage (ft):	9.5341
Roof Outage (Dome Roof)	
Roof Outage (ft):	9.5341
Dome Radius (ft):	139.0000
Shell Radius (ft):	69.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance. (Shell):	0.1700
Tank Paint Solar Absorptance. (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9858
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	26.5341

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

Working Losses (lb):	2,494.6352
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	78,510,000.0000
Number of Turnovers:	26.1700
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	3,000,000.0000
Maximum Liquid Height (ft):	28.0000
Tank Diameter (ft):	139.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	3,750.3651

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	2,494.64	1,255.73	3,750.37