Department of
Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

October 28, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: IPS 510 MW Simple Cycle Project
DEP File No. 1010373-001-AC (PSD-FL-280)

Dear Mr. Worley:

Enclosed for your review and comment is an application for the IPS Shady Hills Generating Station in Pasco County. This facility will be comprised of three nominal 170 MW GE PG7241FA combustion turbines operating in simple cycle mode, one fuel oil storage tank, and ancillary equipment. IPS proposes 3,390 hours of operation per unit. IPS requests up to 1000 hours of 0.05 percent sulfur No. 2 distillate fuel oil use per unit within the requested 3,390 hours.

The site is approximately 28 kilometers south of the Chassahowitzka National Wildlife Area. The applicant proposes NO_X emissions at 9 ppmvd on natural gas and 42 ppmvd on fuel oil with annual emissions as per the table below:

Pollutant	Proposed Facility Emissions (tons per year)
NO_X	756
SO_2	166
CO	259
PM/PM_{10}	61.4
VOC	34.4
SAM	25.4

The project is similar to the Oleander Project. Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact me at (850) 921-9523.

Sincerely,

Teri Tober

A. A. Linero, P.E., Administrator For
New Source Review Section

AAL/jk

Enclosure

Department of Environmental Protection

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Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

October 28, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, CO 80225

Re: IPS 510 MW Simple Cycle Project
DEP File No. 1010373-001-AC (PSD-FL-280)

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the IPS Shady Hills Generating Station in Pasco County. This facility will be comprised of three nominal 170 MW GE PG7241FA combustion turbines operating in simple cycle mode, one fuel oil storage tank, and ancillary equipment. IPS proposes 3,390 hours of operation per unit. IPS requests up to 1000 hours of 0.05 percent sulfur No. 2 distillate fuel oil use per unit within the requested 3,390 hours.

The site is approximately 28 kilometers south of the Chassahowitzka National Wildlife Area. The applicant proposes NO_X emissions at 9 ppmvd on natural gas and 42 ppmvd on fuel oil with annual emissions as per the table below:

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The project is similar to the Oleander Project. Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. If you have any questions, please contact me at (850) 921-9523.

Sincerely,

Teri Tober for

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/jk

Enclosure

- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2), and
- Carbon monoxide (CO).

Pasco County has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is classified as a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow the regulations pertaining to such designations.

The air permit application is divided into seven major sections.

- Section 2.0 presents a description of the facility, including air emissions and stack parameters.
- Section 3.0 summarizes and reviews the PSD requirements applicable to the proposed project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed project with ambient air quality standards (AAQS), PSD increments, and good engineering practice (GEP) stack height regulations.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

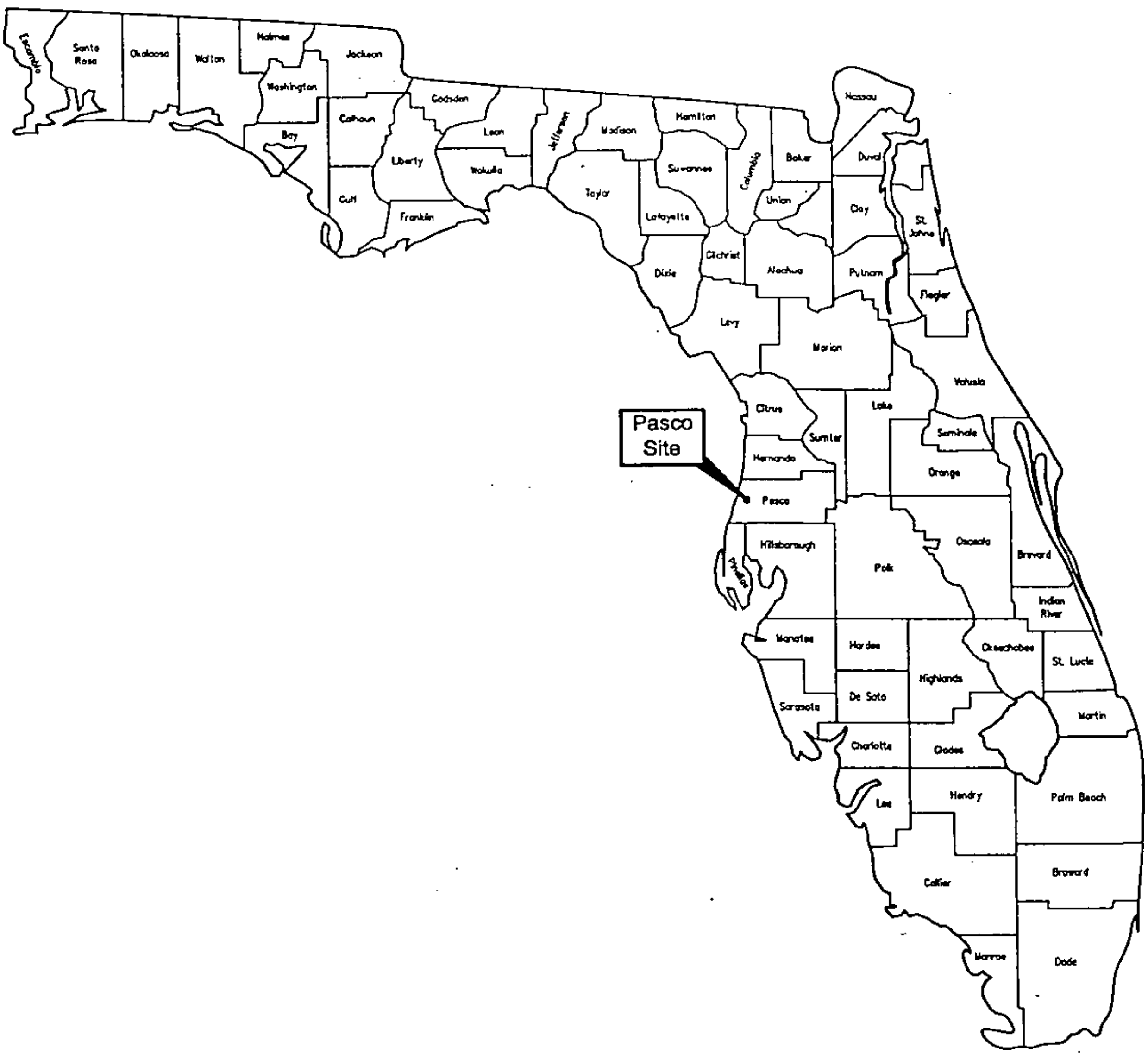

Figure 1-1.
General Location of Pasco Site

Filename: 9939525Y/F1/WP/figure1-1
Date: 10/12/99

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2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The project site, shown in Figure 2-1, consists of about 20 acres that is currently undeveloped. There is minimal industrial and commercial development within a 3-kilometer (km) radius of the site. The plant elevation will be approximately 50 feet above sea level. The terrain surrounding the site is flat.

Natural gas will be supplied by a lateral pipeline connected to the Florida Gas Transmission (FGT) Company's natural gas pipeline located west of the site. The site has access to electrical transmission facilities from a 230-kilovolt (kV) transmission line and electrical substation that is located to the west of the site. Water for the evaporative cooler, and NO_x control when firing oil, will be supplied by Pasco County, but onsite groundwater wells will be available for backup or emergency purposes. Potable water and additional fire protection supply water will be provided from groundwater wells.

2.2 POWER PLANT

The proposed project will consist of three General Electric Frame 7FA CTs and associated facilities. The annual maximum capacity factor of the plant will be 39 percent, which is equivalent to operating 3,390 hours per year at full load. Natural gas will be used as the primary fuel, and fuel oil will be used as a backup fuel. Fuel oil usage will be limited to the equivalent of 1,000 hours per year at full load.

Plant performance with General Electric 7FA CTs was developed for natural gas and oil; at 50-, 75-, and 100-percent load; and at 32 degrees Fahrenheit (°F), 59°F, and 95°F turbine inlet temperatures. Combustion turbine performance is based on a performance envelope developed from General Electric data and has been adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided by the manufacturer's guarantee. In particular, the combustion turbine emission estimates account for 5 percent higher power output and a 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine.

The CTs will be capable of operating from 50 to 100 percent of baseload. The efficiency of the CTs decreases at part load. As a result, IPS Avon Park Corporation will have an economic incentive to dispatch the plant to keep the units operating as near baseload as possible.

Natural gas will be transported to the site via pipeline and fuel oil will be trucked to the site. The distillate fuel oil, which will have a maximum sulfur content of 0.05 percent, will be stored onsite in one aboveground storage tank, sized to hold approximately 67,000 barrels (2.8 million gallons).

Air emissions control will consist of using state-of-the-art DLN burners in the CTs when firing natural gas. The General Electric Frame 7FA will be equipped with the General Electric DLN-2.6 combustion system that regulates the distribution of fuel delivery to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion system fuel nozzle is regulated to maintain unit load and minimize turbine emissions. The DLN-2.6 combustion system consists of six fuel nozzles per combustion can, with each operating as a fully premixed combustor. Of the six nozzles, five are located radically and one is in the center. The fuel system is fully automated and sequences the DLN-2.6 combustion system through a number of staging modes prior to reaching full load. The General Electric Frame 7FA has 14 combustors per turbine. Water injection will be used for NO_x control when firing distillate fuel oil. The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, volatile organic compound (VOC), and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of the proposed CT operating at baseload conditions (100-percent load), 75-percent load and 50-percent load conditions are presented in Tables 2-1 through 2-6. The information is presented in these tables for one unit operating in simple cycle operation, based on natural gas combustion and fuel oil combustion. The data are presented for turbine inlet temperatures of 32°F, 59°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience.

The performance calculations for the operating conditions are given in Appendix A.

The pollutant gaseous emission concentrations and PM_{10} emission rates for the proposed CTs are as follows:

Pollutant	Natural Gas	Distillate Oil
NO_x, ppmvd @ 15 percent O_2	9	42
CO, ppmvd	12	20
VOC as CH_4, ppmvd (gas), ppmvw (oil)	1.4	7
SO_x as SO_2	Calculated Based on Fuel (1.0 grains S/100 SCF)	Calculated Based on Fuel (0.05 percent sulfur)
PM_{10} lb/hr (dry filterable)	10	17

Note: lb/hr = pound per hour
ppmvd = parts per million volume dry
ppmvw = parts per million volume wet

The maximum short-term emission rates (lb/hr) generally occur at baseload, 32°F operation, where the CT has the greatest output and greatest fuel consumption.

Based on a turbine inlet temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the proposed facility for regulated air pollutants are presented in Table 2-7 for one and three CTs. To produce the maximum annual emissions, the CTs are assumed to operate at baseload for 3,390 hours (39 percent capacity factor) firing natural gas for 2,390 hours and fuel oil for 1,000 hours. The potential emissions are based on the 59°F turbine inlet air condition since it represents a nominal average between the higher emission levels at the 32°F turbine inlet condition (winter) and the relatively infrequent 95°F turbine inlet condition (summer).

Process flow diagrams of the turbine operating at turbine inlet temperature of 95°F, 59°F, and 32°F are presented in Figures 2-2 through 2-4, respectively for the "F" Class CT.

Based on a review of the emission rates for natural gas and fuel oil combustion, the highest emission rates for the regulated pollutants generally occur when firing fuel oil. Combustion of natural gas and fuel oil result in slightly different exhaust flow gas rates and stack exit temperatures; however, the differences are minor. As a result of the higher emissions when firing oil, the air modeling analyses were based on determining maximum ground-level impacts with fuel oil.

As discussed in Section 6.0, the air modeling analyses that addressed compliance with ambient standards were based on modeling the CTs for the operating load and ambient temperature which produced the maximum impacts from the load impact analysis that was performed. Although the highest emission rates occur with low turbine inlet temperatures (i.e., 32°F) and baseload conditions, the lowest exhaust gas flow rates occur with a turbine inlet temperature of 95°F and 50 percent operating load. Since this low exhaust flow condition can result in potentially higher impacts due to lower plume rise (i.e., due to lower exit velocity and temperature), the analysis included modeling the CTs for the following four scenarios which are designed to determine the maximum impacts for the project:

- Base operating load for the turbine at an inlet temperature of 32°F;
- Base operating load for the turbine at an inlet temperature of 95°F;
- A 50-percent operating load for the turbine at an inlet temperature of 32°F; and
- A 50-percent operating load for the turbine at an inlet temperature of 95°F.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed facility is presented in Figure 2-5. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6) F.A.C.

Table 2-1. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- Baseload for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,097	1,113	1,135
Velocity (ft/sec)		118.7	116.0	111.1
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	5.1	5.0	4.6
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	66.7	64.1	59.9
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	44.2	42.5	39.3
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.95	2.83	2.62
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.79	0.76	0.71
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-2. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature		
		32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,170	1,179	1,193
Velocity (ft/sec)		100.5	98.2	95.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	4.2	4.0	3.7
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	54.4	52.4	48.3
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	35.7	34.6	32.7
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.38	2.31	2.18
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.65	0.62	0.57
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-3. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with DLN Combustors Firing Natural Gas-- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature		
		32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,171	1,186	1,200
Velocity (ft/sec)		84.2	82.0	80.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	3.4	3.2	2.9
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	43.4	40.8	38.3
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	30.0	28.9	27.8
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.00	1.93	1.85
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.52	0.49	0.45
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-4. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- Baseload for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,076	1,094	1,121
Velocity (ft/sec)		122.4	119.7	115.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	101.5	98.7	93.4
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17.0	17.0	17.0
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	362.0	350.8	335.8
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	74.4	71.4	66.2
	Basis	20 ppmvd	20 ppmvd	20 ppmvd
VOC (as methane)	lb/hr	16.7	16.2	15.3
	Basis	7 ppmvw	7 ppmvw	7 ppmvw
Sulfuric Acid Mist	lb/hr	15.6	15.1	14.3
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-5. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,170	1,176	1,186
Velocity (ft/sec)		101.0	99.6	97.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	82.6	80.1	74.8
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	296.7	285.0	267.8
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	57.6	56.4	53.9
	Basis	20 ppmvd	20 ppmvd	20 ppmvd
VOC (as methane)	lb/hr	13.0	12.8	12.4
	Basis	7 ppmvw	7 ppmvw	7 ppmvw
Sulfuric Acid Mist	lb/hr	12.6	12.3	11.5
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-6. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil-- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,200	1,200	1,200
Velocity (ft/sec)		85.7	83.3	81.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	65.6	62.8	58.9
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	236.4	224.0	209.3
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	72.2	69.8	67.5
	Basis	30 ppmvd	30 ppmvd	30 ppmvd
VOC (as methane)	lb/hr	10.8	10.5	10.3
	Basis	7 ppmvw	7 ppmvw	7 ppmvw
Sulfuric Acid Mist	lb/hr	10.0	9.6	9.0
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-7. Maximum Potential Annual Emissions for the Shady Hills Generating Station Project

	Annual Emissions (tons per years) (1)						
	Natural Gas Firing (2) for Operating Loads			Distillate Oil Firing (3) for Operating Loads			Maximum Emissions
Pollutant	100%	75%	50%	100%	75%	50%	with oil-firing (4)
One Combustion Turbine							
PM	17.0	17.0	17.0	8.5	8.5	8.5	20.5
SO_2	8.4	6.8	5.4	49.3	40.0	31.4	55.3
NO_x	109	88.8	69.2	175.4	142.6	112.0	252
CO	72.0	58.6	49.0	35.7	28.2	34.9	86.5
VOC	4.8	3.9	3.3	8.1	6.4	5.3	11.5
Sulfuric Acid Mist	1.3	1.0	0.8	7.6	6.1	4.8	8.5
Three Combustion Turbines							
PM	50.9	50.9	50.9	25.5	25.5	25.5	61.4
SO_2	25.2	20.5	16.2	148	120	94.2	166
NO_x	326	266	208	526	428	336	756
CO	216	176	147	107	84.5	105	259
VOC	14.4	11.7	9.8	24.3	19.2	15.8	34.4
Sulfuric Acid Mist	3.9	3.1	2.5	22.7	18.4	14.4	25.4

(1) Based on turbine inlet temperature of 59°F.
(2) 3,390 hours per year operation.
(3) 1,000 hours per year operation.
(4) 2,390 hours of gas firing and 1,000 hours of oil firing.

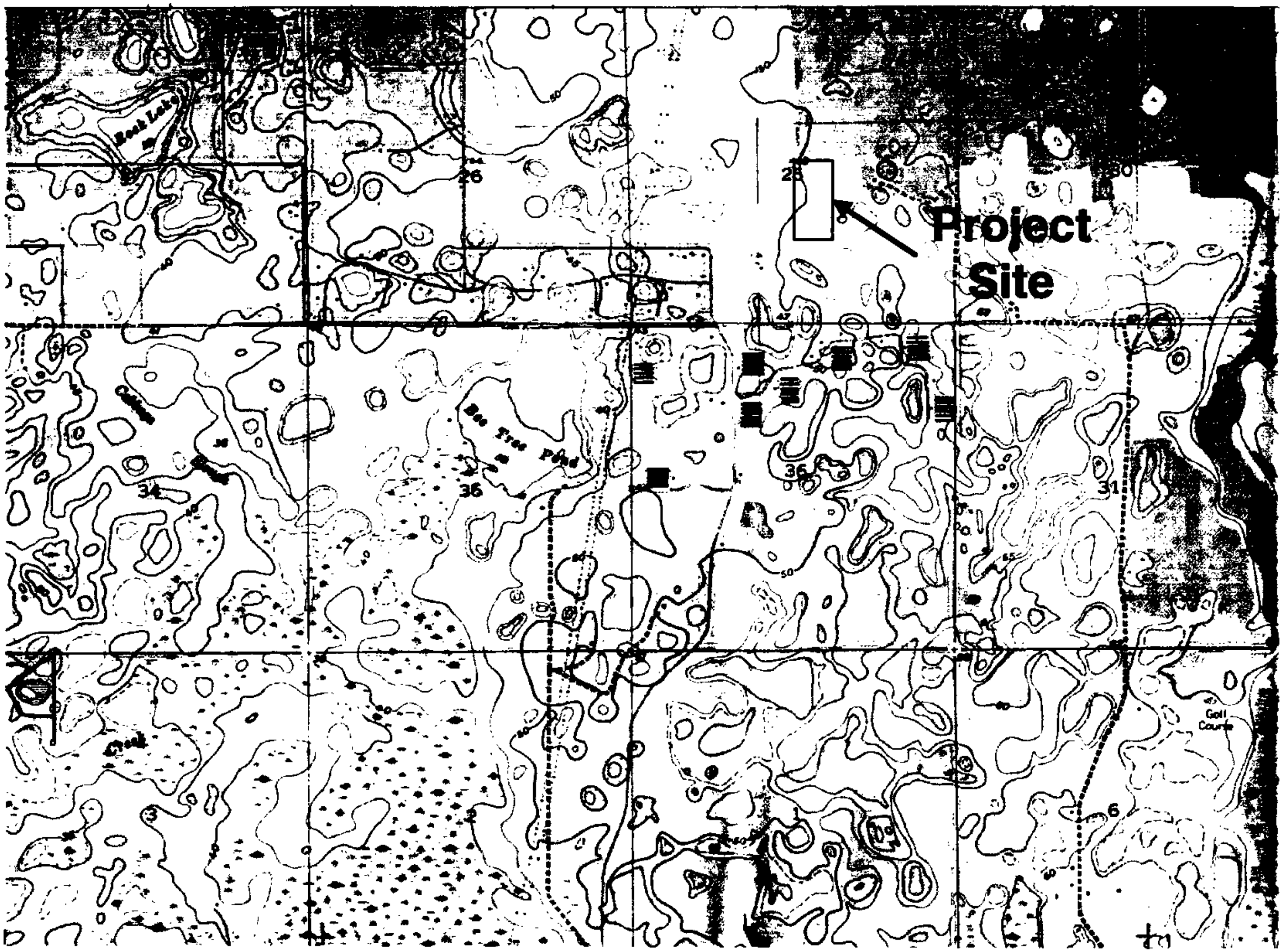
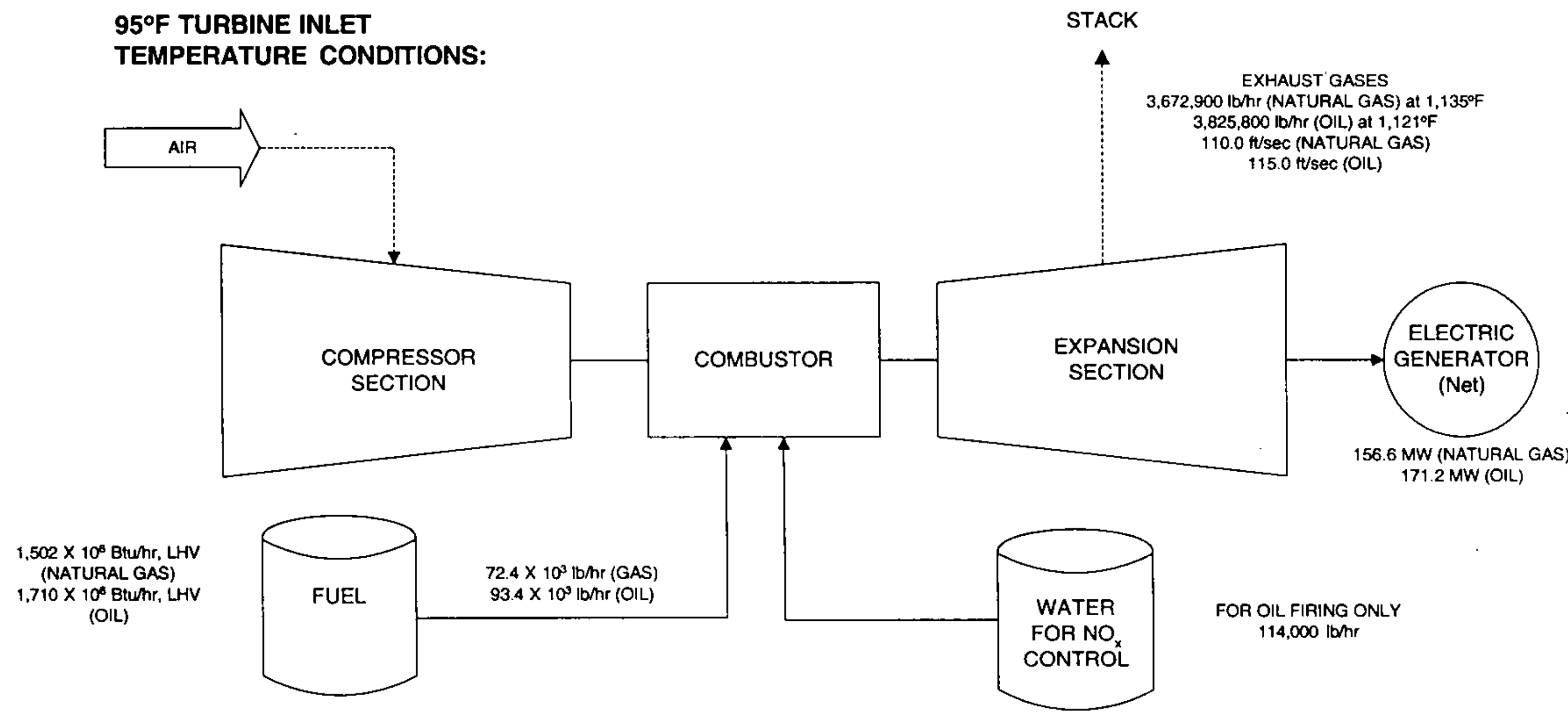


Figure 2-1. Location of Shady Hills Generating Station
IPS Avon Park Corporation

Golder Associates



NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-2
Simplified Flow Diagram of Proposed "F" Class Combustion Turbine
Baseload, Summer Design Conditions

Process Flow Legend
Solid/Liquid ——→
Gas - - - - →
Steam ········→

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Date: 10/12/99

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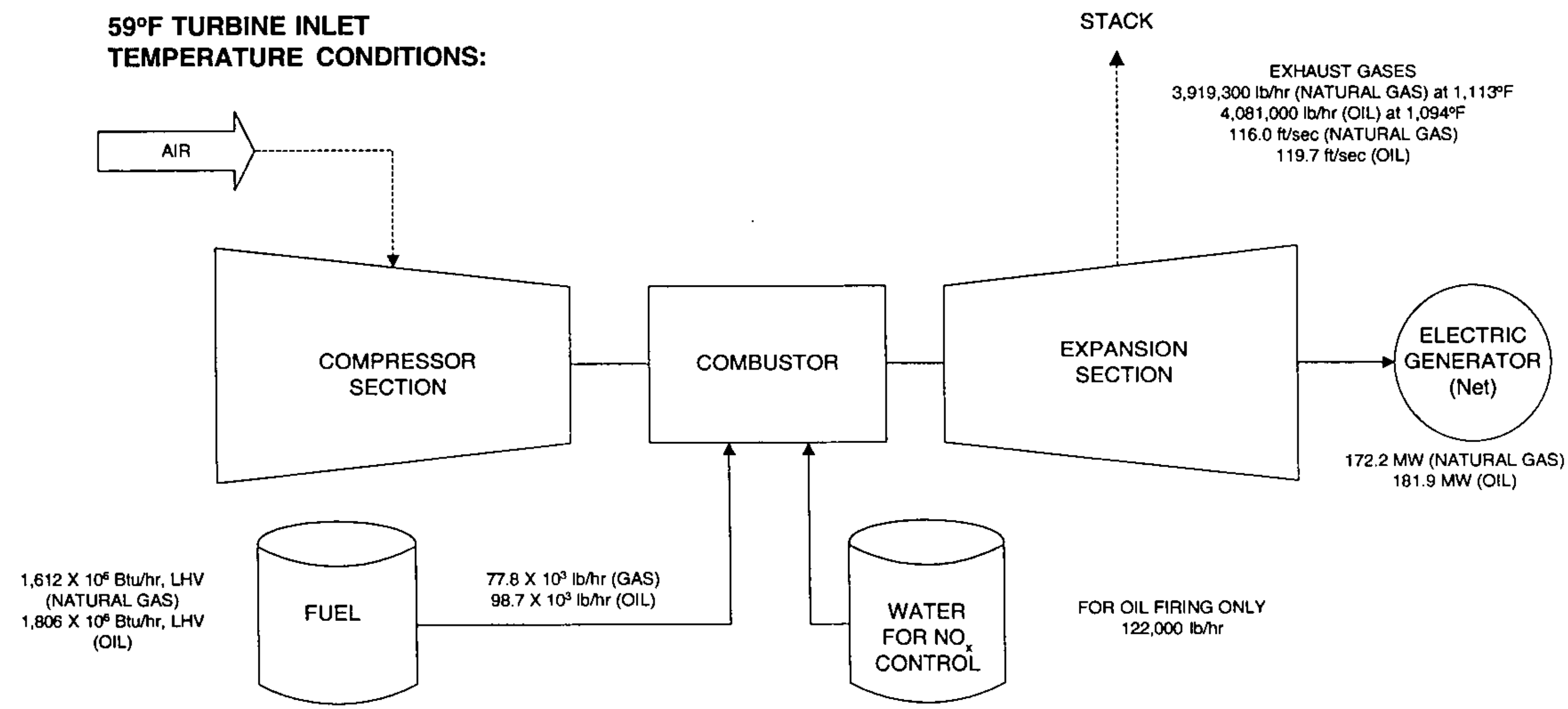

NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-3
Simplified Flow Diagram of Proposed "F" Class Combustion Turbine
Baseload, Annual Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 9939525Y/F1/WP/FIGURES.VSD
Date: 10/12/99

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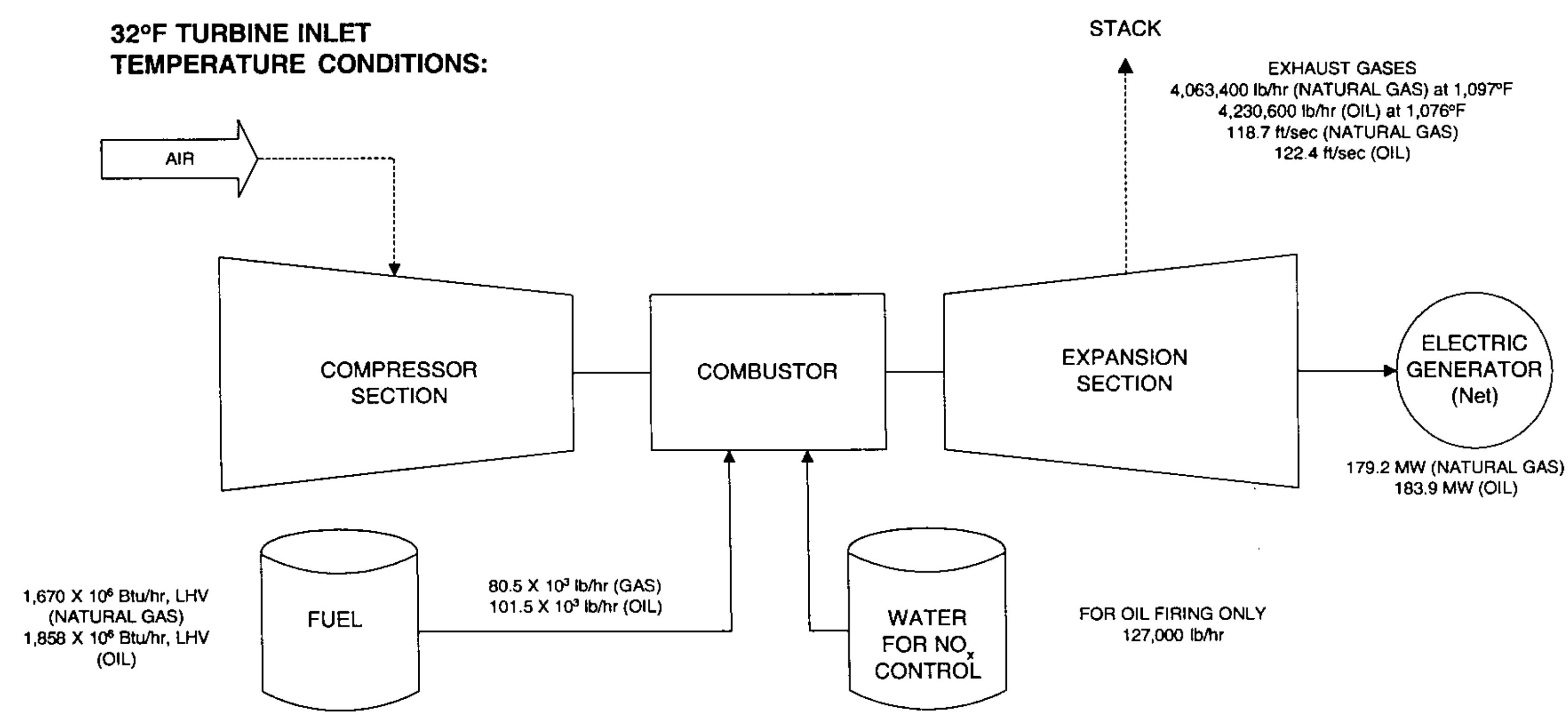

NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-4
Simplified Flow Diagram of Proposed "F" Class Combustion Turbine
Baseload, Winter Design Conditions

Process Flow Legend
Solid/Liquid ———→
Gas - - - - →
Steam ———→

Filename: 9939525Y/F1/WP/FIGURES.VSD
Date: 10/25/99

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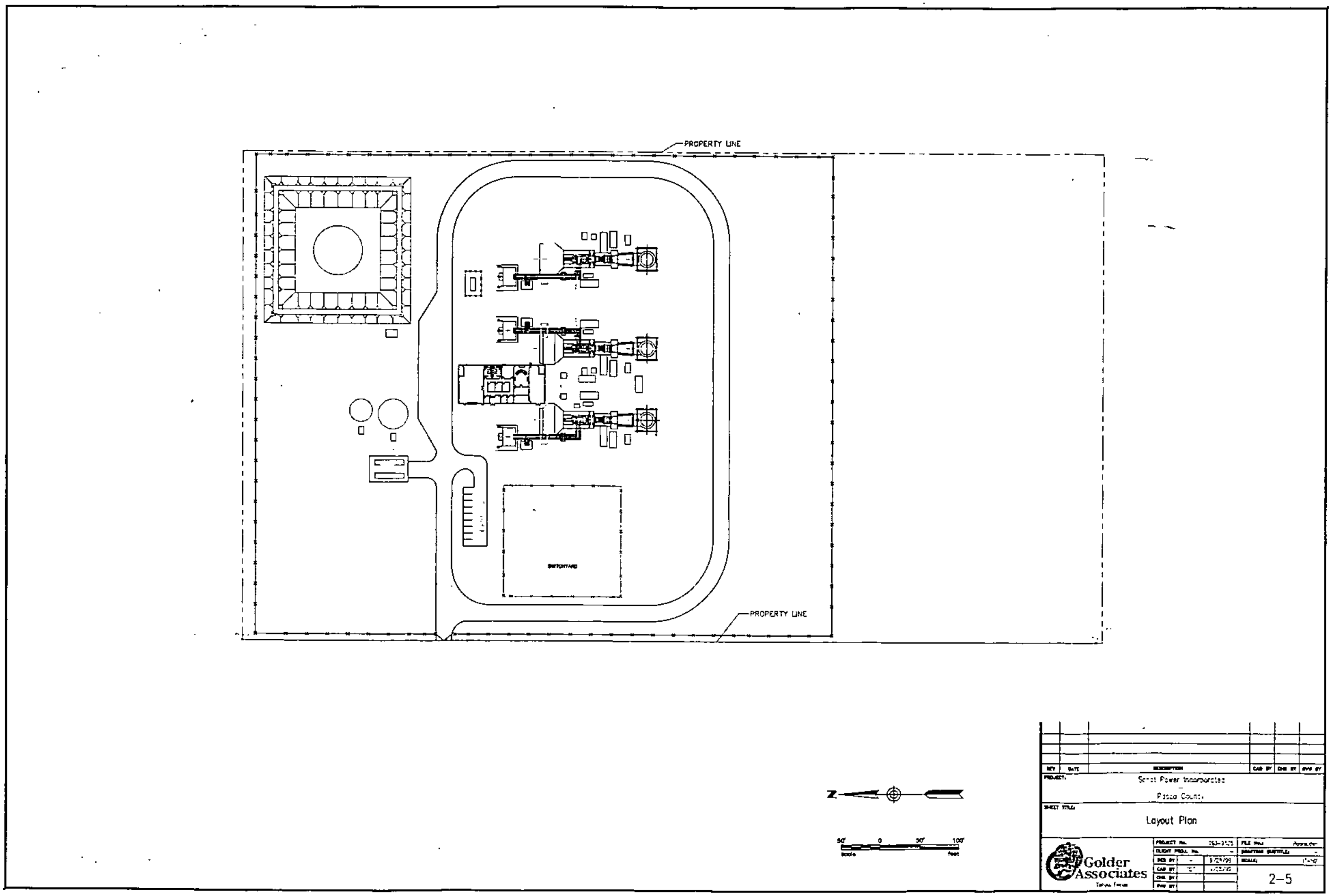
PROPERTY LINE
SWITCHYARD
PROPERTY LINE
N
Layout Plan
Golder Associates
2-5

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed Shady Hills Generating Station.

3.1 NATIONAL AND STATE AAQS

The existing national and Florida AAQS are presented in Table 3-1. Primary AAQS were promulgated to protect the public health with an adequate margin of safety [42 United States Code (USC) Section 7409(b)(1)]. The primary AAQS are designed to protect children, the elderly, and those with respiratory diseases. Secondary AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air [42 USC Section 7409(b)(2)]. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all new or modified major sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a permit issued before the commencement of construction. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to DEP.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Subject to certain exceptions, a "major modification" is defined under PSD regulations as a physical or operational change at an existing major facility that increases the facility's emissions by an amount that is greater than the defined significant emission rates. PSD significant emission rates are shown in Table 3-2.

EPA's regulations identify certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2 increments.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida has adopted PSD regulations which have been approved by EPA [Rule 62-212.400 F.A.C.]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to GEP stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.410, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in 52.21 (b)(12) and Rule 62-210.200(40), F.A.C., as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with new source performance standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA became concerned that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990).

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised). The source impact analysis for criteria pollutants that addresses compliance with AAQS and PSD Class II increments may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below the significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels (SILs) for Class I areas. The NPS, as the designated agency for oversight in air quality impacts to Class I areas, has also recommended significant impact levels for PSD Class I areas. The EPA proposed Class I SILs are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD review, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "HSH" refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM (TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM (TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO2 and PM (TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO2 and PM (TSP), and February 8, 1988, for NO2.

The minor source baseline date for SO_2 and PM (TSP) has been set as December 27, 1977, for the entire State of Florida [Rule 62-204.360(1) and (2), F.A.C.]. The minor source baseline for NO_2 has been set as March 28, 1988 [Rule 62-204.360(3), F.A.C.]. It should be noted that references to PM (TSP) are also applicable to PM_{10}.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that Florida DEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.).

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

Source information must be provided to adequately describe the proposed project. The general type of information required for this project is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by Florida DEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 m; or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o); Rule 62-212.400(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed project will be subject to one or more NSPS. The CTs will be subject to 40 CFR Part 60, Subpart GG, and the fuel oil storage tank (2.8 million gallon capacity) will be subject to 40 CFR Part 60, Subpart Kb.

3.4.1.1 Combustion Turbine

The CTs will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour [10 million British thermal units per hour (MMBtu/hr)], based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15 percent oxygen and heat rate while sulfur dioxide emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notification, record keeping, reporting, performance testing and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(2) Notification of the date of initial start-up - no more than 60 days or less than 30 days prior to date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date which demonstrates continuous emission monitoring (CEM) - not less than 30 days prior to date.

60.7 (b) Maintain records of the start-up, shutdown, and malfunction quarterly.

(c) Excess emissions reports - by the 30th day following end of quarter. (required even if no excess emissions occur)

(d) Maintain file of all measurements for two years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

(a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ±5 percent.

(b) Monitor sulfur and nitrogen content of fuel.

Oil - (1): each occasion that fuel is transferred to bulk storage tank.

Gas - (2): daily monitoring required

3.4.1.2 Fuel Oil Storage Tank

The applicable NSPS is 40 CFR Part 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984). The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb. There are no emission limiting or control requirements under Subpart Kb for the use of distillate fuel oil. The facility, however, must perform record keeping of the type of organic liquid in the tank.

3.4.2 FLORIDA RULES

The Florida DEP regulations for new stationary sources are covered in the F.A.C. The Florida DEP has adopted the EPA NSPS by reference in Rule 62-204.800(7); subsection (b)39 for stationary gas turbines and (b)16 for volatile organic liquid storage vessels. Therefore, the project is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. DEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The Florida DEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.052, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The Florida DEP has published guidelines (DEP, 1995) to determine whether any emission of a potentially hazardous or toxic pollutant can pose a possible health risk to the public. Maximum concentrations for all regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants can be compared to ambient reference concentrations (ARCs) for each applicable pollutant. If the maximum predicted concentrations for any hazardous pollutant is less than the corresponding ARC for each applicable averaging time, that emission is considered not to pose a significant health risk. The ARCs are not environmental standards but, rather, evaluation tools to determine if an apparent threat to the public health may exist. These levels are not used in permitting new sources.

3.4.5 LOCAL AIR REGULATIONS

Pasco County has not adopted its own air regulations.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in Pasco County, which has been designated by EPA and DEP as an attainment area for all criteria pollutants. Pasco County and surrounding counties are designated as PSD Class II areas for SO_2, PM (TSP) , and NO_2. The nearest Class I areas to the site is the Chassahowitzka National Wilderness Area (NWA) which is about 28 km (17 miles) from the site.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 250 TPY; therefore, PSD review is required for any pollutant for which the emissions are considered major or exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed project will be major for NO_x and CO and have potential emissions that are greater than the significant emission rates for PM (TSP), PM_{10}, SO_2, and sulfuric acid mist. Because the proposed project's impacts for these pollutants are predicted to be below the significant impact levels, a modeling analysis incorporating the impacts from other sources is not required. (Note: EPA has promulgated changes to the PSD Rules to eliminate hazardous air pollutants (HAPs) from PSD review. The pollutants, vinyl chloride, mercury, asbestos, and beryllium, are no longer evaluated in PSD review.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed project's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I areas to the plant site is about 28 km from the site. A PSD Class I increment-consumption analysis is required because the project's impacts are greater than the proposed EPA Class I significant impact levels.

3.5.2.2 Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0).

The fuel oil storage tank will have a maximum storage capacity of 2.8 million gallons of No. 2 fuel oil. Since the storage tank has a capacity greater than 40 cubic meters (m^3) (approximately 10,568 gallons), the applicable NSPS is 40 CFR Part 60, Subpart Kb. The storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb, with a true vapor pressure of 0.022 pound per square inch (psi) at 100 F. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa) or 0.51 psi, only the minor monitoring of operating requirements specified in 40 CFR 60 116b(a) and (b) will apply.

3.5.2.3 Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant (see Table 3-4), a pre-construction ambient air quality monitoring analysis is required for PM_{10}, SO_2, NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of the pollutant is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement may be obtained [52.21(i)(8)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If pre-construction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data or the collection of onsite data.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels and criteria. Therefore, the project is exempt from the preconstruction ambient air quality monitoring requirements.

3.5.2.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The CT stacks for the project will be 60 ft. This stack height does not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CTs' emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The project site is located in Pasco County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CAA REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), an allowance system (Part 73), CEM (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the later of

January 1, 2000, or the date on which the unit begins serving an electric generator (greater than 25 MW).

The permit would provide SO_2 and NO_x emission limitations and the requirement to hold emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded. For the proposed project, SO_2 allowances will be obtained from the market.

CEM for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_X monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu g/m^3$) Primary Standard	AAQS ($\mu g/m^3$) Secondary Standard	AAQS ($\mu g/m^3$) Florida	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	Significant Impact Levels ($\mu g/m^3$)[b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[a]	365	NA	260	5	91	5
	3-Hour Maximum[a]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[a]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[a]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). These standards have been stayed by a court case against EPA; implementation of these standards appears to be years away.

[d] 0.08 parts per million (ppm); achieved when 3-year average of 99th percentile is 0.08 ppm or less. These have been stayed by a court case against EPA. EPA is appealing. The 1-hour standard of 0.12 ppm is still applicable. FDEP has not yet adopted the new standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.; 40 CFR 50; 40 CFR 52.21.; Chapter 62-204, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] (µg/m3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM (TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	$3.5x10^{-6}$	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = micrograms per cubic meter.
MWC = Municipal waste combustor
MSW = Municipal solid waste

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Sources: 40 CFR 52.21.
Rule 62-212.400

Table 3-3. Maximum Emissions Due to the Proposed Shady Hills Generating Station Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Proposed Facility[a]	Significant Emission Rate	
Sulfur Dioxide	166	40	Yes
Particulate Matter [PM (TSP)]	61	25	Yes
Particulate Matter (PM_{10})	61	15	Yes
Nitrogen Dioxide	756	40	Yes
Carbon Monoxide	259	100	Yes
Volatile Organic Compounds	34	40	No
Lead	0.03	0.6	No
Sulfuric Acid Mist	25	7	Yes
Total Fluorides	0.093	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	0.0018	0.1	No
MWC Organics (as 2,3,7,8-TCDD)	0.00000098	0.0000035	No
MWC Metals (as Be, Cd)	0.010	15	No
MWC Acid Gasser (as HCl)	0.61	40	No

Note: NEG = Negligible.

[a] Based on emissions from three CTs operating at baseload at 59°F; firing natural gas and distillate fuel oil for 2,390 and 1,000 hours per year per turbine, respectively (Refer to Table 2-7).

Table 3-4. Predicted Net Increase in Impacts Due to the Proposed Shady Hills Generating Station Compared to PSD *De Minimis* Monitoring Concentrations

Pollutant	Concentration (µg/m3) Predicted Increase in Impacts[a]	*De Minimis* Monitoring Concentration; Averaging Period
Sulfur Dioxide	0.8	13; 24-hour
Particulate Matter (PM_{10})	0.19	10; 24-hour
Nitrogen Dioxide	0.21	14; annual
Carbon Monoxide	1.6	575; 8-hour

Note: NA = not applicable.
NM = no ambient measurement method.
TPY = tons per year.

[a] See Section 6.0 for air dispersion modeling results.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted in amounts that are greater than the PSD significant emission rates shown in Table 3-2. In this case, the control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed GE 7FA CTs are summarized below (see Table 2-7):

Pollutant Emissions (TPY)

Pollutant	3 GE 7FA CTs
NO_x	756
SO_2	166
CO	256
PM/PM_{10}	61
Sulfuric Acid Mist	25

[a] Maximum emissions based on firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours at baseload conditions and 59°F.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12); and Rule 62-210.200(42), and Rule 62-214.410, F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15 percent oxygen. For the CTs being considered for the project, the NSPS emission limit NO_x with the NSPS heat rate correction is 109.4 parts per million (ppm) on gas and 103.1 ppm (corrected to 15 percent oxygen) on oil at a fuel-bound nitrogen content of 0.015 percent. The proposed NO_x emission limits for the project will be much lower than the NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 PROPOSED BACT

In recent permitting actions, FDEP has established BACT for heavy-duty industrial gas turbines like the ones proposed for the Shady Hills Generating Station. DEP's decisions have been based on the use of advanced DLN combustors for limiting NO_x and CO emissions and clean fuels (natural gas and distillate oil) for control of other emissions, including SO_2. The BACT proposed for IPS Avon Park Corporation's CTs is consistent with these recent FDEP permits. The proposed project will have two modes of operation (see Section 2.3) for which a BACT analysis has been performed. The results of the analysis have concluded that the following controls are BACT for IPS Avon Park Corporation's project.

1. Natural Gas Fired. The CTs will utilize state-of-the-art DLN combustion technology which will achieve gas turbine exhaust NO_x levels of no greater than 9 ppmvd (corrected to 15 percent O_2). CO emissions will be limited to 12 ppmvd at baseload.
2. Fuel Oil Fired. The CT will utilize water injection to achieve gas turbine exhaust NO_x levels of no greater than 42 ppmvd (corrected to 15 percent O_2). CO emissions will be limited to 20 ppmvd at baseload.

4.3.2 NITROGEN OXIDES

4.3.2.1 Introduction

The BACT analysis was performed for the following alternatives:

1. Advanced DLN combustors at an emission rate of 9 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil.

2. Selective catalytic reduction (SCR) and advanced DLN combustors at an emission rate of approximately 3.6 ppmvd corrected to 15 percent O_2 when firing natural gas and 16.8 ppmvd when firing oil.

Appendix B presents a discussion of NO_x control technologies and their feasibility for the project.

DLN combustor technology has recently been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_x emissions of 25 ppmvd (corrected to 15-percent O_2) and less have been offered by manufacturers for advanced CTs. Advanced in this context are the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) CTs. This technology is truly pollution prevention because NO_x emissions are inhibited from forming.

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. The reaction occurs typically between 600°F and 750°F, which has limited SCR application to combined cycle units where such temperatures occur in the heat-recovery steam generator (HRSG). Exhausts from simple cycle operation range up to 1,200°F, thus limiting SCR application for this mode of operation. If SCR is used, with the higher cost ceramic catalyst, temperatures up to 1,050°F are possible. Such SCR systems are referred to as "hot" SCR. To accommodate "hot" SCR in the "F" Class gas turbine, some gas cooling would be required to maintain temperatures below 1,050°F. In-duct cooling using about 110,000 actual cubic feet per minute (acfm) of ambient air would maintain temperatures at or below 1,050°F with turbine flow of about 2,600,000 acfm and up to 1,200°F temperatures in the exhaust gas. This approach could be accomplished with an electric powered fan rated at about 200 kW. While such modifications are theoretically possible, such gas cooling and its effectiveness have not been demonstrated on a "F" Class simple cycle gas turbine. SCR has been primarily installed and operated on combined cycle facilities using catalysts with temperature ranges from 600-750°F and generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning only natural gas.

Applications of SCR with oil firing are limited. Where oil firing has been attempted, catalyst poisoning and ammonium salt formation has occurred. Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic, and special precautions in materials and ammonia injection rates must be implemented to minimize their formation. Ammonia injected in the SCR system that does not react with NO_x is emitted directly into the atmosphere and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 10 ppmvd; however, permitted limits in some applications have exceeded 25 ppmvd. While SCR is technically feasible for the IPS Avon Park Corporation project, SCR has not been applied to a simple cycle advanced combustion turbine of the size proposed for this project or to a facility approved for the amount of oil firing that may occur in this case.

The recent permitting trend for advanced CTs, even with combined cycle configuration, is the use of DLN combustors. Indeed, most of the recent Florida projects have been permitted with this technology, including Florida Power & Light's Martin Units 3 and 4, Central Florida Cogeneration Project, Hardee Unit 3 Project, City of Tallahassee Project, FPL Fort Myers Repowering Project, Duke New Smyrna Beach, Oleander Power Project, and FPL Sanford Repowering Project.

As discussed in Section 2.1, the proposed CTs will be fired primarily with natural gas. Distillate oil will be used as backup fuel, but not to exceed 1,000 hours per year. Table 4-1 presents a summary of emissions with DLN combustors and with DLN combustors and SCR assuming 39 percent operating capacity at an ambient temperature of 59°F. The NO_x removed using SCR would be 151 TPY when firing oil and natural gas. The NO_x removed when firing oil is based on 1,000 hours per year. The NO_x removed when firing natural gas is based on 2,390 hours of operation.

4.3.2.2 Proposed BACT and Rationale

The proposed BACT for the project is advanced DLN combustion technology. The proposed NO_x emissions level using this technology is 9 ppmvd (corrected to 15 percent oxygen) when firing natural gas under baseload conditions. NO_x from oil firing will be controlled using water injection (42 ppmvd corrected to 15 percent oxygen). This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. Table 4-2 summarizes these considerations which favor the DLN pollution prevention technology.
2. The estimated incremental cost of SCR is approximately $14,900 per ton of NO_x removed and is similar to the cost for other projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst). While NO_x emissions would be reduced by about 151 TPY per unit with SCR, the net emissions reduction would not be as great. There are three additional factors that must be considered:
   a. Ammonia slip would occur, and it may be as high as 40.4 TPY per unit.
   b. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 17.1 TPY per unit additional particulate matter may be formed.
   c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced because the proposed project would be an efficient peaking power plant while operating. Any peaking power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the emissions of an additional 4.7 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.

d. The "net" cost effectiveness could be as high as $25,300 per ton of pollutant removed.

4. The energy impacts of SCR will reduce potential electrical power generation by more than 3.9 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 326 residential customers.

5. The proposed BACT (i.e., DLN combustion) provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). DLN combustion at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to conventional CTs, the use of IPS Avon Park Corporation's proposed CTs will result in 10 to 15 percent less NO_x emission while producing the same amount of electricity.

The analyses of economic, environmental, and energy impacts follow.

4.3.2.3 Impact Analysis

Economic--The total capital costs of SCR for the proposed plant are $5,263,200 per CT. The total annualized cost of applying SCR with DLN combustion is $2,250,700. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the DLN combustors and water injection (for oil firing) is estimated at $14,900 per ton of NO_x removed.

Environmental--The maximum predicted NO_x impacts using the DLN technology are all considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$, annual average, and the AAQS of 100 $\mu g/m^3$, annual average. Indeed, the maximum annual impact for the project is 0.3 $\mu g/m^3$, which is only about 30 percent of the significant impact level. While additional controls beyond DLN combustors (i.e., SCR and SCR with water injection) would reduce emissions, the effect will not be significant and much less than 1 percent of the PSD increment and the AAQS for the project.

The use of DLN combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 40.4 TPY/per unit for the project. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10}; up to 17.1 TPY/per unit could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the project. This power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-3. This table shows the emissions balance for the project with and without SCR. As shown, the net reduction in emissions with SCR when all criteria pollutants are considered will be 89 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were included in Table 4-3. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using DLN combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: CAA (Section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Energy--Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 0.50 percent over that of advanced low-NO_x combustors. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 2,967,290 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 949,200 kWh per yr. Taken together, the total lost generation and energy requirements of SCR of 3,916,490 kWh per year could supply the monthly electrical needs of about 326 residential customers. To replace this lost energy, an additional 41 x 10^{10} British thermal units per year (Btu/yr) or about 41 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The proposed project will use an advanced heavy-duty industrial gas turbine with advanced DLN combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the proposed GE Frame 7FA advanced machine is about 170 MW compared to the 70 MW to 120 MW conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing lower air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 9 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10^6 Btu, which is less than half of the emissions generated from conventional fossil fuel-fired steam generators.

Since the purpose of the project is to produce electrical energy, and CT technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The heat rate of the GE 7FA machines will be about 9,360 Btu/kWh (LHV, 59°F, natural gas). In contrast, the heat rate for a new conventional CT is about 11,000 Btu/kWh. Therefore, the amount of total NO_x from the advanced CT will be more than 10-percent lower than a conventional turbine for the same amount of generation.

Also, the amount of NO_x control achieved by the DLN combustor on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater NO_x emission formation. Since the advanced machine has higher firing temperatures, the NO_x emissions without the use of DLN combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NO_x reduction on the advanced CT.

4.3.3 CARBON MONOXIDE

4.3.3.1 Introduction

Emissions of CO are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO as well as NO_x emissions.

For the project, the following alternatives were evaluated as BACT:

1. Combustion controls at 12 ppmvd when firing natural gas (at baseload) and 20 ppmvd when firing oil (at baseload); and

2. Oxidation catalyst at 80 percent removal; maximum annual CO emissions are 17 TPY per unit.

4.3.3.2 Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 12 ppmvd when firing natural gas and 20 ppmvd when firing distillate oil at baseload conditions. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts;
2. The economic impacts are significant (i.e., the capital cost is about $1.7 million per unit, with an analyzed cost of $466,000 per year per unit); and
3. Recent projects in Florida have been authorized with BACT emission limits of 25 ppmvd on gas and 90 ppmvd on oil.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 30 ppmvd range and higher. Even the Northeast States for Coordinated Air Use Management (NESCAUM) has recognized a BACT level of 50 ppmvd for CO emissions. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

4.3.3.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $466,000 per unit, resulting in a cost effectiveness of greater than $9,000 per ton of CO removed. The cost effectiveness is based on 2,390 hours per year on natural gas and 1,000 hours per year of operation on oil. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts at the proposed CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in acidic deposition, to reducing CO.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,186,900 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 99 residential customers for a year. To replace this lost energy, about 1.2×10^{10} Btu/yr or about 12 million ft^3/yr of natural gas would be required.

4.3.4 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT as a result of incomplete combustion. The proposed BACT for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions will not exceed 1.4 ppmvd when firing natural gas and 7.0 ppmvw when firing distillate oil. These emission levels are similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

4.3.5 PM/PM_{10}, SO_2 AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PM/PM_{10} emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas- or oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions [about 10 pounds per hour (lb/hr) when firing natural gas]} is less than 0.01 grain per standard cubic foot, which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

There are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil, represent BACT for these pollutants. The use of natural gas and very low sulfur (0.05 percent) fuel oil will limit emissions of SO_2 and sulfuric acid mist.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherently low contaminant content.

Table 4-1. NO_x Emission Estimates (TPY) of BACT Alternative Technologies (per Unit)

Alternative BACT Control Technologies	Operating Mode[a]		Total
	Oil	Gas	
NO_x Emission (TPY)			
DLN only	175.4	76.6	252.0
DLN with SCR[b]	70.2	30.6	100.8
Reduction	(105.2)	(46.0)	(151.2)
Basis of Emissions (ppmvd)			
DLN only	42	9	
DLN with SCR	16.8	3.6	
Hours of Operation	1,000	2,390	3,390

Note: DLN = Dry low-NO_x.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Emission rates were based on a "F" class combustion turbine operating at 100-percent capacity and firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours. Emission data are based on an ambient temperature of 50°F at maximum emission rates.

[b] Based on primary emissions with SCR; no account is made for additional emissions (secondary) due to lost energy from heat rate penalty and electrical usage for SCR operation (see Table 4-3).

Table 4-2. Comparison of Alternative BACT Control Technologies for NO_x (per Unit)

	Alternative BACT Control Technologies	
	DLN Only	SCR
Technical Feasibility	Feasible	Feasible for gas
Economic Impact[a]		
Capital Costs	included	$5,263,200
Annualized Costs	included	$2,250,700
Cost Effectiveness		
NO_x Removed (per ton of NO_x)	NA	$14,886
NO_x Removed (per ton of total pollutants)	NA	25,267
Environmental Impact[b]		
Total NO_x (TPY)	252	101
NO_x Reduction (TPY)	NA	(151.2)
Ammonia Emissions (TPY)	0	40.4
PM Emissions (TPY)	0	17.1
Secondary Emissions (TPY)	0	4.7
Net Emission Reduction (TPY)	NA	(89.1)
Energy Impacts[c]		
Energy Use (kWh/yr)	0	3,916,490
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	40,696
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	41
Energy Use (residential customers)	0	326

[a] See Appendix B for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table 4-3.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 3,390 hours per year. Lost energy is based on 0.5 percent of 175.06 MW. SCR electrical usage is based on 0.080 MWh per SCR system and 0.20 MWh for cooling fan.

Table 4-3. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

Pollutants		Incremental Emissions (tons/year) of SCR		
		Primary	Secondary	Total
Particulate		17.10	0.15	17.25
Sulfur Dioxide			0.06	0.06
Nitrogen Oxides		-151.20	2.71	-148.49
Carbon Monoxide			1.63	1.63
Volatile Organic Compounds			0.11	0.11
Ammonia		40.37		
	Total:	-93.73	4.65	-89.08
Carbon Dioxide (additional from gas firing)			2,577.43	2,577.43

Basis:

Lost Energy (mmBtu/year)	40,696

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the Act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality.

A major source may waive the ambient monitoring analysis requirement if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels. The maximum impacts of the proposed source are compared with the PSD *de minimis* concentrations in Table 3-4. As can be seen from Table 3-4, the proposed plant's maximum air quality impacts will be well below the *de minimis* concentrations for all applicable pollutants.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines for determining compliance with AAQS and PSD increments. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA significant impact levels at any off-plant property areas in the vicinity of the plant.

If the project's impacts are above the significant impact levels, then a more detailed air modeling analysis that includes background sources is performed. Current Florida DEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. Based on the screening modeling analysis results, additional modeling refinements with a denser receptor grid are performed, as necessary, to obtain the maximum concentration. Modeling refinements are performed with a receptor grid spacing of 100 meters (m) or less.

For this project, the significant impacts levels were calculated in the vicinity of the plant following Florida DEP policies.

Generally, if a new project also is within 150 km of a PSD Class I area, then a significant impact analysis is also performed for the PSD Class I area. Currently, the National Park Service (NPS) has recommended significant impact levels for PSD Class I areas. The recommended levels have not been promulgated as rules. EPA also has proposed PSD Class I significant impact levels that have not been finalized as of this report.

Because the proposed project site is approximately 28 km from the Chassahowitzka NWA PSD Class I area, a significant impact modeling analysis has been performed.

6.2 PRECONSTRUCTION MONITORING ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines. The project's impacts were compared to the *de minimis* monitoring levels to determine whether it would be necessary to submit continuous monitoring data to DEP prior to construction. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a *de minimis* impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA *de minimis* levels at any off-plant property areas in the vicinity of the plant. Current Florida DEP policies stipulate that the highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

A proposed major stationary facility or major modification may be exempt from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels.

For this project, the project's impacts were calculated in the vicinity of the plant for comparison to *de minimis* levels following Florida DEP policies. As presented in Section 5.0, since the project's VOC emissions are lower than the *de minimis* VOC emission level, the project is exempt from preconstruction ambient monitoring requirements.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider the project's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest annual and the highest short-term concentrations for comparison to the significant impact levels and *de minimis* levels.

If the project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations, and calculate the cumulative impact of these sources for comparison to ambient standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the HSH concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor at which the maximum concentration was predicted. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements employ an angular spacing between radials of 2 degrees and a distance interval from 100 to 300 m, depending on the concentration gradient in the vicinity of the screening receptor to be refined. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid will extend to all adjacent screening receptors. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid highest concentration is obtained. A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids are presented in the following sections.

6.3.2 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 99155) dispersion model (EPA, 1997) was used to evaluate the pollutant impacts due to the proposed CTs. This model is maintained by the EPA on its Internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can run in the rural or urban land use mode which affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent of the land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the proposed plant site (see Figure 2-1), the rural dispersion coefficients were used in the modeling analysis.

The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. When evaluating the project's impacts only for comparison to the significant impact and *de minimis* monitoring levels, a generic emission rate of 10 grams per second (g/s) was used as emissions for the proposed source. Maximum pollutant-specific air impacts for the project were then determined by multiplying the maximum pollutant-specific emission rate, in pounds per hour, by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

6.3.3 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at the Tampa International Airport in Tampa, Florida, and at Ruskin, Florida, respectively. The 5-year period of meteorological data was from 1987 through 1991. These data are the most recent 5-year period of meteorological data that have been approved by DEP for use in the modeling. The NWS station at Tampa is located approximately 40 km (24 miles) to the south of the proposed plant site while the NWS station at Ruskin is located approximately 70 km (42 miles) south of the proposed plant site. The surface meteorological data from Tampa are assumed to be representative of the project site because both the project site and the weather station are located in similar topographical areas and are situated in central Florida to experience similar weather conditions, such as frontal passages.

6.3.4 EMISSION INVENTORY

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs used in the air modeling analysis is presented in Tables 2-1 through 2-6. The emission and stack operating parameters presented for 32°F and 95°F ambient temperatures for both natural gas and distillate fuel oil were used in the modeling to determine the maximum air quality impacts for a range of possible operating conditions.

Six modeling scenarios per fuel type were considered:

1. Base operating load at an inlet temperature of 32°F;
2. Base operating load at an inlet temperature of 95°F;
3. 75 percent operating load at an inlet temperature of 32°F;
4. 75 percent operating load at an inlet temperature of 95°F;
5. 50 percent operating load at an inlet temperature of 32°F; and
6. 50 percent operating load at an inlet temperature of 95°F.

The proposed CTs will have a stack height of 60 ft and an inner stack diameter of 22 ft.

6.3.5 RECEPTOR LOCATIONS

For predicting maximum concentrations in the vicinity of the plant, a polar receptor grid comprised of 693 grid receptors was used. These receptors included 36 receptors located on radials extending out from the proposed CTs' stack locations. Along each radial, receptors were located at the plant property and distances of 0.1, 0.2, 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 2.5, 3.0, 4.0, 5.0, 7.0, 10.0, 12.0, 15.0, 20.0, 25.0, and 30.0 km from the proposed CT No 2 stack location. The closest property boundary to the stack is 85 m.

Modeling refinements were performed, as needed, by employing a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of 2 degrees.

Since the terrain surrounding the proposed plant site varies little from the stack base elevation of 50 ft above MSL, the terrain was assumed to be flat and receptor elevations were set equal to the stack base elevation.

6.3.6 BUILDING DOWNWASH EFFECTS

The only significant structures in the vicinity of the proposed CT stacks are the proposed CT air filter inlets, CT structure, fuel oil storage tank, and demineralizer water tanks. The height and widths of these structures are as follows:

Structure	Height (ft)	Width (ft)	Length (ft)
CT air inlet	47	24	36
CT structure	22	30	42
Fuel oil tank	50	100 (diameter)	Not applicable
Demin. water tank	50	100 (diameter)	Not applicable

Building dimensions for the project's structures were entered into the EPA's Building Profile Input Program (BPIP, Version 95086) for the purpose of obtaining direction-specific building heights and widths for all downwash-affected sources. The direction-specific building dimensions were then input to the ISCST3 model as the building height and width for each of 36 ten-degree wind sectors. A summary of the direction-specific building dimensions used in the modeling is presented in Appendix C.

6.4 AIR MODELING RESULTS

The modeling analysis results for the proposed CTs alone in the vicinity of the plant are summarized in Tables 6-2 through 6-4. The maximum pollutant concentrations predicted in the screening analysis for a single CT and three CTs firing natural gas and distillate fuel oil are presented in Tables 6-2 and 6-3, respectively. A summary of the maximum pollutant concentrations predicted for the project compared to the Class II significant impact levels, PSD Class II increments, and AAQS is shown in Table 6-5.

As shown in the tables, the maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are all below the significant impact levels. Because the proposed source will not have a significant impact upon the air quality in the vicinity of the plant site, more detailed modeling analyses for determining compliance with the AAQS and PSD Class II increments are not required.

The maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are also below the *de minimis* monitoring levels. Because the proposed source will not have predicted impacts greater than *de minimis* levels, preconstruction monitoring data are not required to be submitted as part of the PSD review.

The modeling analysis results for the proposed CTs alone at the Chassahowitzka NWA are summarized in Tables 6-5 through 6-7. The maximum pollutant concentrations predicted in the screening analysis for a single CT and three CTs firing natural gas and distillate fuel oil are presented in Tables 6-6 and 6-7, respectively. A summary of maximum pollutant concentrations predicted for the project compared to the Class I significant impact levels and PSD Class I increments are presented in Table 6-7.

As shown in the tables, the maximum predicted PM and NO_2 impacts due to the proposed CTs are all below EPA's proposed PSD Class I significant impact levels. Therefore, more detailed modeling analyses for determining compliance with the AAQS and PSD Class II increments are not required for these pollutants. For SO_2, the maximum annual average impacts from the CTs are predicted to be below the proposed EPA significant impact levels while the maximum 3-hour and 24-hour average impacts from the CTs are predicted to be above the significant impact levels. As a result, more detailed modeling for the 3-hour and 24-hour average SO_2 concentrations was performed to assess PSD Class I increment consumption at the Chassahowitzka NWA.

Summaries of the ISCST3 model results for each year are presented in Appendix D. Examples of the model input file are also provided in Appendix D.

The detailed modeling involved assessing air quality impacts 3-hour and 24-hour average SO_2 from PSD sources located within about 150 km from the Chassahowitzka NWA. Based on discussions with the Florida DEP and National Park Service, these analyses should be performed using a long-range transport model that can assess impacts for sources located more than 50 km from the Class I area and is acceptable to the Florida DEP, EPA, and National Park Service. From these discussions, the California PUFF (CALPUFF) long-range transport model was recommended and determined to be acceptable by the reviewing agencies. As a result, the CALPUFF model was used to assess the 3-hour and 24-hour average SO_2 concentration for PSD sources, including the project, located within 150 km of the Class I area. A description of the CALPUFF model, including methods and assumptions used in the analysis, is presented in Appendix E. A detailed listing of the PSD sources used in the modeling is presented in Appendix F. This inventory was used in a recent PSD permit application that addressed SO_2 increment consumption in the Class I area.

A summary of maximum 3-hour and 24-hour average SO_2 concentrations predicted for PSD sources at the Class I area is presented in Table 6-8. As shown in Table 6-8, there were one and three violations of the 3-hour and 24-hour average PSD Class I increments, respectively, predicted in the Class I area. For these locations and periods for which the violations were predicted, the project's impacts were less than the proposed EPA significant impact levels. In fact, the project's impacts were zero or essentially zero with a predicted impact of 0.0004 $\mu g/m^3$ for one of the 24-hour violations.

Based on these analyses, the project's impacts are predicted to comply with the PSD Class I increments and not have a significant impact at the Class I area when violations of the 3-hour and 24-hour average PSD Class I increments are predicted.

Copies of the CALPUFF model input and output files, including those from CALPOST that summarize the CALPUFF results, are provided in Appendix G.

Table 6-1. Major Features of the ISCST3 Model, Version 99155

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing including setting wind speeds less than 1 meters per second(m/s) to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term.
Source: EPA, 1999.

Table 6-2. Maximum Pollutant Concentrations Predicted for One Combustion Turbine Firing Natural Fuel and Distillate Fuel Oil in Simple-Cycle Operation in the Project Vicinity

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)					
	Base Load		75% Load		50% Load		Averaging	Base Load		75% Load		50% Load	
Pollutant	32°F	95°F	32°F	95°F	32°F	95°F	Time	32°F	95°F	32°F	95°F	32°F	95°F
Natural Gas													
Generic	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0155	0.0165	0.0183	0.0193	0.0219	0.0229
(10 g/s)							24-Hour	0.2006	0.2103	0.2282	0.2426	0.2714	0.2817
							8-Hour	0.4347	0.4572	0.4977	0.5194	0.5810	0.6041
							3-Hour	0.8216	0.9642	0.9772	0.9837	1.1910	1.2004
							1-Hour	1.7590	1.8765	2.1112	2.1693	2.5525	2.5669
SO_2	5.1	4.6	4.2	3.7	3.4	2.9	Annual	0.00099	0.00095	0.00097	0.00090	0.00094	0.00084
							24-Hour	0.0129	0.0122	0.0121	0.0113	0.0116	0.0103
							3-Hour	0.053	0.056	0.052	0.046	0.051	0.044
PM10	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.0020	0.0021	0.0023	0.0024	0.0028	0.0029
							24-Hour	0.0253	0.0265	0.0287	0.0306	0.0342	0.0355
NO_x	66.7	59.9	54.4	48.3	43.4	38.3	Annual	0.013	0.012	0.013	0.012	0.012	0.011
CO	44.2	39.3	35.7	32.7	30.0	27.8	8-Hour	0.24	0.23	0.22	0.21	0.22	0.21
							1-Hour	0.98	0.93	0.95	0.89	0.96	0.90
Distillate Fuel Oil													
Generic	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0151	0.0159	0.0182	0.0189	0.0214	0.0225
(10 g/s)							24-Hour	0.1965	0.2050	0.2269	0.2391	0.2654	0.2781
							8-Hour	0.4253	0.4450	0.4950	0.5112	0.5689	0.5960
							3-Hour	0.8184	0.9601	0.9763	0.9813	1.1854	1.1970
							1-Hour	1.7080	1.8169	2.1093	2.1572	2.5071	2.5617
SO_2	101.5	93.4	82.6	74.8	65.6	58.9	Annual	0.019	0.019	0.019	0.018	0.018	0.017
							24-Hour	0.25	0.24	0.24	0.23	0.22	0.21
							3-Hour	1.05	1.13	1.02	0.92	0.98	0.89
PM10	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.0032	0.0034	0.0039	0.0041	0.0046	0.0048
							24-Hour	0.042	0.044	0.049	0.051	0.057	0.060
NO_x	362.0	335.8	296.7	267.8	236.4	209.3	Annual	0.069	0.067	0.068	0.064	0.064	0.059
CO	74.4	66.2	57.6	53.9	72.2	67.5	8-Hour	0.40	0.37	0.36	0.35	0.52	0.51
							1-Hour	1.60	1.52	1.53	1.47	2.28	2.18

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table 6-3. Maximum Pollutant Concentrations Predicted for Three Simple-Cycle Combustion Turbines Firing Natural Gas and Distillate Fuel Oil Compared to the EPA PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1): Base Load 32°F	Base Load 95°F	75% Load 32°F	75% Load 95°F	50% Load 32°F	50% Load 95°F	EPA Class II Significant Impact Levels (ug/m^3)
Natural Gas								
SO_2	Annual	0.0030	0.0029	0.0029	0.0027	0.0028	0.0025	1
	24-Hour	0.039	0.037	0.036	0.034	0.035	0.031	5
	3-Hour	0.158	0.168	0.155	0.138	0.153	0.132	25
PM10	Annual	0.0059	0.0062	0.0069	0.0073	0.0083	0.0087	1
	24-Hour	0.076	0.079	0.086	0.092	0.103	0.106	5
NO_x	Annual	0.039	0.037	0.038	0.035	0.036	0.033	1
CO	8-Hour	0.73	0.68	0.67	0.64	0.66	0.63	500
	1-Hour	2.9	2.8	2.8	2.7	2.9	2.7	2,000
Distillate Fuel Oil								
SO_2	Annual	0.058	0.056	0.057	0.053	0.053	0.050	1
	24-Hour	0.75	0.72	0.71	0.68	0.66	0.62	5
	3-Hour	3.1	3.4	3.0	2.8	2.9	2.7	25
PM10	Annual	0.0097	0.0102	0.0117	0.0122	0.0137	0.0145	1
	24-Hour	0.126	0.132	0.146	0.154	0.171	0.179	5
NO_x	Annual	0.21	0.20	0.20	0.19	0.19	0.18	1
CO	8-Hour	1.20	1.11	1.08	1.04	1.55	1.52	500
	1-Hour	4.8	4.5	4.6	4.4	6.8	6.5	2,000

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table 6-4. Summary of Maximum Pollutant Concentrations Predicted for Three Simple-Cycle Combustion Turbines Compared to the EPA Class II Significant Impact Levels, PSD Class II Increments, and AAQS

Pollutant	Averaging Time	Maximum Concentration (ug/m^3)		EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increments (ug/m^3)	AAQS (ug/m^3)
		Natural Gas	Distillate Fuel Oil			
SO_2	Annual	0.0030	0.060	1	25	60
	24-Hour	0.039	0.82	5	91	260
	3-Hour	0.17	3.6	25	512	1,300
PM_{10}	Annual	0.0087	0.015	1	17	50
	24-Hour	0.106	0.19	5	30	150
NO_x	Annual	0.039	0.21	1	25	100
CO	8-Hour	0.73	1.6	500	NA	10,000
	1-Hour	2.9	6.8	2,000	NA	40,000

NA= not applicable

Table 6-5. Maximum Pollutant Concentrations Predicted for One Combustion Turbine Firing Natural Fuel and Distillate Fuel Oil in Simple-Cycle Operation at the PSD Class I Area of the Chassahowitzka NWA

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)					
	Base Load		75% Load		50% Load		Averaging	Base Load		75% Load		50% Load	
Pollutant	32°F	95°F	32°F	95°F	32°F	95°F	Time	32°F	95°F	32°F	95°F	32°F	95°F
Natural Gas													
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0066	0.0070	0.0076	0.0080	0.0090	0.0094
							24-Hour	0.1083	0.1148	0.1255	0.1312	0.1478	0.1533
							8-Hour	0.2799	0.2943	0.3202	0.3341	0.3739	0.3870
							3-Hour	0.6412	0.6669	0.7125	0.7361	0.8022	0.8230
							1-Hour	0.8707	0.9176	1.0019	1.0469	1.1738	1.2169
SO_2	5.1	4.6	4.2	3.7	3.4	2.9	Annual	0.00042	0.00041	0.00040	0.00037	0.00039	0.00034
							24-Hour	0.0070	0.0067	0.0066	0.0061	0.0063	0.0056
							3-Hour	0.041	0.039	0.038	0.034	0.034	0.030
PM10	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.0008	0.0009	0.0010	0.0010	0.0011	0.0012
							24-Hour	0.0136	0.0145	0.0158	0.0165	0.0186	0.0193
NO_x	66.7	59.9	54.4	48.3	43.4	38.3	Annual	0.006	0.005	0.005	0.005	0.005	0.005
Distillate Fuel Oil													
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0065	0.0068	0.0076	0.0079	0.0089	0.0092
							24-Hour	0.1058	0.1116	0.1247	0.1291	0.1445	0.1514
							8-Hour	0.2739	0.2865	0.3185	0.3289	0.3660	0.3824
							3-Hour	0.6303	0.6529	0.7094	0.7272	0.7892	0.8157
							1-Hour	0.8509	0.8922	0.9962	1.0299	1.1491	1.2013
SO_2	101.5	93.4	82.6	74.8	65.6	58.9	Annual	0.008	0.008	0.008	0.007	0.007	0.007
							24-Hour	0.14	0.13	0.13	0.12	0.12	0.11
							3-Hour	0.81	0.77	0.74	0.69	0.65	0.61
PM10	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.0014	0.0015	0.0016	0.0017	0.0019	0.0020
							24-Hour	0.023	0.024	0.027	0.028	0.031	0.032
NO_x	362.0	335.8	296.7	267.8	236.4	209.3	Annual	0.030	0.029	0.028	0.027	0.026	0.024

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table 6-6. Maximum Pollutant Concentrations Predicted for Three Simple-Cycle Combustion Turbines Firing Natural Gas and Distillate Fuel Oil Compared to the EPA PSD Class I Significant Impact Levels

		Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)						EPA Class I Significant Impact Levels (ug/m^3)
		Base Load		75% Load		50% Load		
Pollutant	Averaging Time	32°F	95°F	32°F	95°F	32°F	95°F	
Natural Gas								
SO_2	Annual	0.00127	0.00122	0.00121	0.00112	0.00116	0.00103	0.1
	24-Hour	0.021	0.020	0.020	0.018	0.019	0.017	0.2
	3-Hour	0.124	0.116	0.113	0.103	0.103	0.090	1.0
PM10	Annual	0.0025	0.0027	0.0029	0.0030	0.0034	0.0035	0.2
	24-Hour	0.041	0.043	0.047	0.050	0.056	0.058	0.3
NO_x	Annual	0.017	0.016	0.016	0.015	0.015	0.014	0.1
Distillate Fuel Oil								
SO_2	Annual	0.025	0.024	0.024	0.022	0.022	0.021	0.1
	24-Hour	0.406	0.394	0.389	0.365	0.358	0.337	0.2
	3-Hour	2.42	2.31	2.21	2.06	1.96	1.82	1.0
PM10	Annual	0.004	0.004	0.005	0.005	0.006	0.006	0.2
	24-Hour	0.068	0.072	0.080	0.083	0.093	0.097	0.3
NO_x	Annual	0.089	0.086	0.085	0.080	0.079	0.073	0.1

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table 6-7. Summary of Maximum Pollutant Concentrations Predicted for Three Simple-Cycle Combustion Turbines Compared to the EPA Class I Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Time	Maximum Concentration (ug/m^3)		EPA Class I Significant Impact Levels (ug/m^3)	PSD Class I Increments (ug/m^3)
		Natural Gas	Distillate Fuel Oil		
SO_2	Annual	0.00127	0.025	0.1	2
	24-Hour	0.021	0.41	0.2	5
	3-Hour	0.124	2.4	1.0	25
PM10	Annual	0.0035	0.0059	0.2	4
	24-Hour	0.058	0.097	0.3	8
NO_x	Annual	0.017	0.089	0.1	2.5

Table 6-8. Summary of Maximum 3-hour and 24-hour Average SO_2 Concentrations Predicted for PSD Sources at the Chassahowitzka NWA Compared to the PSD Class I Increments (CALPUFF Model)

Averaging Time	Maximum Concentration [a] (ug/m^3)	Project's Contribution (ug/m^3)	Receptor Location (m) UTM East	Receptor Location (m) UTM North	Period Ending (Julian day/ hour/year)	PSD Class I Increments (ug/m^3)	EPA Class I Significant Impact Levels (ug/m^3)
24-Hour	5.33	0.0	340,700	3,171,900	253/24/90	5	0.2
	5.09	0.0004	340,300	3,167,700	135/24/90		
	5.01	0.0	340,300	3,165,700	336/24/90		
3-Hour	29.6	0.0	334,000	3,183,400	143/12/90	25	1.0

[a] Maximum concentration is the highest, second highest or lower value predicted at the Class I area (i.e., concentration that exceeds the Class I increment).

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 INTRODUCTION

The additional impact analysis addresses the potential impacts of the new power facility on vegetation, soils, and wildlife of the surrounding area and the nearest Class I area. The nearest Class I area is the Chassahowitzka NWA, located approximately 28 km northwest of the proposed project. Because the facility is subject to the PSD NSR requirements for SO_2, PM_{10}, NO_2, CO, and sulfuric acid emissions, the additional impact analysis were performed for these pollutants. The analyses also addressed impacts associated with the project firing natural gas and backup distillate fuel oil.

According to the modeling results presented in Section 6.0, the maximum air quality impacts predicted for the project are well below the EPA's Class II significant impact levels, the PSD Class II increments, and the AAQS. The maximum air quality impacts predicted for the project are also below the EPA's Class I significant impact levels and the PSD Class I increments, except for the 3-hour and 24-hour average SO_2 concentrations. However, the project's impacts are predicted to be less than the Class I significant impact levels when exceedances of the Class I increment are predicted. As a result, regardless of the existing conditions in the vicinity of the site or in the Class I areas, the proposed project will not result in any significant adverse effects upon these areas.

7.2 SOIL, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

As shown in Section 6.0, the maximum air quality impacts for the project were predicted in the vicinity of the project and in the Class I area. The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants and comparing them to the lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made to assess the pollutant interaction with the different matrices (i.e., vegetation, soils, wildlife, and aquatic environment).

A screening approach was used to evaluate potential effects that compared the maximum predicted ambient concentrations of air pollutants of concern with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the plant and the Class I area. It was recognized that effects threshold information is not available for all species found in the Chassahowitzka NWA, although studies have been performed on a few of the common species and on other similar species which can be used as models.

7.3 IMPACTS TO PLANT VICINITY SOILS AND VEGETATION

According to the USDA Pasco County Soil Survey, soils in the vicinity of the project are classified as Candler fine sand, an excessively drained, sloping soil found in the sandhill areas of Pasco County. Excessively drained, sandy soils are by nature acidic, therefore agricultural uses require amendment of soil with lime to increase alkalinity.

Vegetative communities in the vicinity of the project site are primarily pine plantation, improved pasture, xeric oak hammock, and maintained lawns associated with the wastewater treatment plant and access road right-of-ways.

Maximum predicted concentrations of SO_2, PM_{10}, NO_2, and CO in the vicinity of the project site are at least an order of magnitude lower than the EPA Class II significant impact levels (see Table 6-4); therefore, no significant impacts associated with facility operations are expected. The predicted concentrations are less than 1 percent of the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area.

7.4 CLASS I AREA IMPACT ANALYSIS

7.4.1 IDENTIFICATION OF AQRV AND METHODOLOGY

An AQRV analysis was conducted to assess the potential risk to AQRVs of the Chassahowitzka NWA due to the proposed increase from the proposed facility. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register 1978).

Except for visibility, AQRVs were not specifically defined. However, odor, soil, flora, fauna, cultural resources, geological features, water, and climate generally have been identified by land managers as AQRVs. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found in the Chassahowitzka NWA.

Vegetation type AQRVs and their representative species types have been defined as:

- Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass
- Marsh Islands - cabbage palm and eastern red cedar
- Estuarine Habitat - black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp - red maple, red bay, sweet bay, and cabbage palm
- Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto
- Mangrove Swamp - red, white, and black mangrove

Wildlife AQRVs have been identified as endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles, and mammals.

A screening approach was used that compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWA with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the NWA. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the Chassahowitzka NWA, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

7.4.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

According to the USDA Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the Chassahowitzka NWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale-Rock outcrop, Homosassa mucky fine sandy loam, Lacooche, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee, and Weekiwachee-Durbin mucks (Porter, 1996). The majority of the soil complexes found in the NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and therefore have a relatively high intrinsic buffering capacity.

The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Chassahowitzka NWA from the proposed plant emissions precludes any significant impact on soils.

7.4.3 VEGETATION

7.4.3.1 General

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

The response of vegetation and wildlife to atmospheric pollutants is influenced by the concentration of the pollutant, duration of exposure, and frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants and animals they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

7.4.3.2 SO_2

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury

generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 in the Chassahowitzka NWA average 1.29 $\mu g/m^3$, with a 24-hour maximum concentration of 14.5 $\mu g/m^3$. Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

Two lichen species indigenous to Florida exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu g/m^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).

The maximum 24-hour SO_2 concentrations predicted within the Class I area due to the project only are 0.021 $\mu g/m^3$ when operating with natural gas and 0.50 $\mu g/m^3$ when firing distillate fuel oil. When added to the average background concentration of 1.29 $\mu g/m^3$, total SO_2 impacts are 1.31 and 1.79 $\mu g/m^3$, for natural gas and distillate fuel oil, respectively. When added to the maximum 24-hour background concentrations for the NWA (14.5 $\mu g/m^3$), the resultant worst-case scenario concentrations are 14.52 and 15 $\mu g/m^3$ for natural gas and distillate fuel oil, respectively. This level is much lower than those known to cause damage to test species. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979). Under worst-case scenarios when the plant is operating on backup fuel, the maximum 24-hour SO_2 concentrations predicted within the Class I area are only 3.8 to 7.5 percent of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

7.4.3.3 PM_{10}

Although information pertaining to the effects of particulate matter on plants is scarce, some concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of particulate matter that ranged from 210 to 366 μg/m^3 for an 8-hour averaging

period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of particulate matter lower than 163 μg/m^3 did not appear to be injurious to the tested plants.

By comparison of these published toxicity values for particulate matter exposure (i.e., concentrations for an 8-hour averaging time), the possibility of plant damage in the Chassahowitzka NWA can be determined. The maximum predicted cumulative 8-hour PM_{10} concentration in the NWA due to the project only is 0.146 μg/m^3 when firing natural gas, and 0.246 μg/m^3 when firing distillate fuel oil (see Table 7-1). When added to the average background concentrations recorded for the NWA (21.1 μg/m^3, 24-hour averaging time), the resultant concentrations are 21.2 and 21.3 μg/m^3, respectively. This concentration is well below the lower threshold value that reportedly affects plant foliage. When added to the maximum PM10 concentrations recorded in the NWA (83.6 μg/m^3, 24 hour averaging time), the worst case scenario concentrations are 83.7 and 83.8 μg/m^3 when firing natural gas or fuel oil, respectively. In any event, since the project contributes only 0.146 μg/m^3, 8-hour average impact, to the total predicted impacts, no effects to vegetative AQRVs are expected from the project.

7.4.3.4 NO_2

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, noninjurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru et al., 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

Short term (8 hour averaging time) predicted NO_x emissions in the Class I area due to the project only are 0.706 and 3.75 $\mu g/m^3$ for natural gas and fuel oil, respectively. These concentrations are less than 0.1 percent of the levels that cause foliar injury in acute exposure scenarios. By comparison of published toxicity values for NO_2 exposure to long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the Class I areas can be examined for chronic exposure situations. For a chronic exposure, the annual estimated NO_2 concentrations due to the project only at the point of maximum impact in the Class I areas are 0.017 and 0.089 $\mu g/m^3$.

when the project is firing natural gas and fuel oil, respectively. These values are less than 0.01 percent of the levels that caused minimal yield loss and chlorosis in plant tissue. The average and maximum background NO_2 concentrations reported in the Chassahowitzka NWA are 0.006 and 0.104 $\mu g/m^3$, respectively.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the wilderness areas are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.4.3.5 CO

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok et al. (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I areas can be determined. The predicted maximum annual concentrations due to the project only in the Class I area are 0.011 and 0.024 $\mu g/m^3$ for natural gas and fuel oil, respectively. These concentrations are <0.00001 percent of the minimum value that caused inhibition in laboratory studies.

7.4.3.6 SUMMARY

In summary, the phytotoxic effects from the proposed plant emissions are minimal. It is important to note that the elements were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.4.4 WILDLIFE

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National AAQS. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of SO_2, NO_2, and particulates which are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from SO_2, NO_2, and particulates are expected. The proposed project's contribution to cumulative impacts is negligible.

7.4.5 IMPACTS UPON VISIBILITY

The Clean Air Act Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

The analysis to determine the potential adverse plume visibility effects in the Chassahowitzka NWA was based on using the screening approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992), which has been computerized by EPA in a program called the VISCREEN model. The VISCREEN model is currently recommended for use by the EPA to assess visual plume impacts in regulatory applications. The VISCREEN model can be used to calculate potential plume impact of specific pollutant emissions for specific transport and meteorological dispersion conditions.

The model can be applied in two successive levels of screening (i.e., referred to as Levels 1 and 2) without the need for extensive source, meteorological, or pollutant input. If the screening calculations demonstrate that, during worst-case meteorological conditions a plume is imperceptible or, if perceptible, is not likely to be considered objectionable ("adverse" or "significant" in the language of the EPA PSD and visibility regulations), further analysis of plume visual impact would not be required as part of the air quality review of the source. However, if the screening analyses demonstrate that the criteria are exceeded, plume visual impacts cannot be ruled out, and more detailed analyses to ascertain the magnitude, frequency, location, and timing of plume visual impacts would be required.

The Level 1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts that would be larger than those calculated with more realistic input and modeling assumptions). This analysis assumes worst-case meteorological conditions of stable stability (Pasquill-Gifford stability class F) and a 1 m/s wind speed persisting for 12 hours in one direction towards a PSD Class I area. The input required for the Level 1 analysis is limited to the following parameters:

- Emission rates of PM_{10} and NO_x;
- Distance between the emission source and (a) the observer; (b) the closest Class I area boundary; and (c) the most distant Class I area boundary;
- Background visual range appropriate for the region in which the Class I area is located; and
- If available, emission rates of NO2, soot, and primary sulfate.

Visibility impacts are then determined for two parameters:

- Contrast of a plume against a viewing background such as the sky or a terrain feature, and
- Perceptibility of a plume on the basis of the color difference between the plume and the viewing background (Delta E).

Results are provided by the model for several scenarios based on the background view, the viewing angle, visibility improvement due to plumes located both inside and outside the

Class I area, and the sun angle. The critical values for contrast and Delta E are 0.05 and 2.00, respectively. If these levels are not exceeded by the proposed source, the source is considered to pass the Level 1 visibility analysis, and the source will not have a significant impact on the Class I area.

The only PSD Class I area located within 150 km of the project site is the Chassahowitzka NWA. The terrain between the project site and PSD Class I area and within the Class I area can be considered as generally flat. With no terrain feature that can be used as a viewing background, the visibility impacts were determined using the sky as the only viewing background.

The visibility impact analysis for the project was performed for the project firing natural gas, the primary fuel, and distillate fuel oil that, which the backup fuel. It should be note that the proposed CTs will operate up to a maximum of 3,390 hours in a year with the backup fuel oil limited to 1,000 hours per year. In reality, because the CTs are peaker units operating in simple-cycle mode, the CTs will operate for fewer hours than those proposed. Also, because of the economic difference in cost between firing natural gas and fuel oil, the CTs will fire fuel oil on an infrequent basis. It should also be noted that the CTs, as peaking units, will operate during the daytime from about 7 a.m. to 7 p.m. when electrical demand is highest.

The input parameters and results of the Level 1 analysis for the project firing natural gas and fuel oil are presented in Figures 7-1 and 7-2. As shown, the project will emit PM_{10}, NO_x, and primary SO_4 (as sulfuric acid mist). The maximum short-term average emission rates used in the analysis, which are presented in Section 2.0 and Appendix A, are based on the CTs operating at baseload conditions with an air inlet temperature of 32°F. These rates are higher for fuel oil-firing than those for natural gas-firing. Primary NO_2 and soot are not emitted in significant quantities by natural gas- and oil-fired combustion sources; therefore, these emissions were set to zero.

The PSD Class I area of the Chassahowitzka NWA is located to the north and north-northwest of the project site at distances that vary from approximately 28 km to 47 km. Therefore, the frequencies associated with these two wind directions were included in the analysis (i.e., south and south-southeast) with the highest frequency from any of those directions used in the cumulative frequency to determine the worst-case meteorology. Since the CTs are most likely to operate during the daytime, the weather frequencies for these wind directions were determined for the daytime and nighttime periods. The daytime period corresponded to the 12-hour period from 7 a.m. to 7 p.m. while the nighttime period corresponded to the 12-hour period from 7 p.m. to 7 a.m.

This analysis is presented in Table 7-5, which shows the dispersion product term, transport time to the nearest part of the Class I area (i.e., distance of 27.8 km), and the frequency associated with each wind direction. As indicated in Table 7-5, the meteorological conditions considered in the analysis could be transported to the Class I area in less than 12 hours. As a result, all of these conditions would be included in determining the worst-case meteorology using the cumulative probability of 1 percent.

As shown in Table 7-5, during the nighttime period, two weather conditions for both wind directions produce a cumulative frequency of 1 percent or more (moderately stable stability and wind speeds of 0.8 and 2.6 m/s. However, the CTs are not likely to operate during the nighttime. By considering the daytime period when the CTs are likely to operate, the weather condition of neutral (D class) stability and wind speed of 4.4 m/s is associated with a cumulative frequency of 1 percent. This weather condition was used to assess the potential visual plume impacts from the project.

The results of the visual plume impact analysis for the CTs firing natural gas and fuel oil using a worst-case meteorological condition of neutral stability and 4.4 m/s wind speed are shown in Figures 7-3 and 7-4, respectively. For natural gas-firing, all values of Delta E and contrast are less than the screening criteria of 2.00 and 0.05, respectively. As a result, it is highly unlikely that the pollutant emissions from the project firing natural gas will cause adverse visibility impairment in the Chassahowitzka NWA.

For oil-firing, all values of Delta E and contrast are less than the screening criteria of 2.00 and 0.05, respectively, except for maximum visual impacts outside of the Class I area when the plume is viewed against a sky background. The Delta E for the project is estimated to be 2.25 compared to a criterion of 2.0. This scenario assumes that the plume is between the observer and the sun that is located at an angle of 10 degrees above the horizon in a direction to the southeast or southwest of the observer. In reality, such a sun angle and direction are not likely to occur for any given line of sight from the Class I area to the project. The furthest southward extent of the sun's location at these latitudes is to the east-southeast or west-southwest. By limiting the southward extent of sun's location to these directions and to a 10-degree angle above the horizon, the Delta E for the project is estimated to be less than the criterion of 2.0.

It should also be noted that these critical visual impacts are estimated for locations outside of the Class I area. This evaluation is important if there were integral vistas located outside the Class I area. However, no integral vistas have been identified for the Chassahowitzka NWA.

Given that the CTs will be firing natural gas as a primary fuel and are proposed to operate for 39 percent of the time or less during the year (including 11 percent or less with fuel oil), it is highly unlikely that the pollutant emissions from the project firing natural gas or fuel oil will cause adverse visibility impairment in the Chassahowitzka NWA.

7.5 ADDITIONAL GROWTH

Construction of the new plant will result in an increase in jobs, payroll, and taxes in the area. However, no significant growth-related impacts are expected due to the proposed project.

Table 7-1. Maximum Predicted Concentrations due to the Project Only at the Class I Area of the Chassahowitzka National Wilderness Area

Natural Gas	Concentrations[a] ($\mu g/m^3$) for Averaging Times				
Pollutant	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0013	0.021	0.054	0.124	0.168
Nitrogen Dioxide (NO_2)	0.017	0.273	0.706	1.62	2.20
Particulates (PM_{10})	0.0035	0.058	0.146	0.311	0.460
Carbon Monoxide (CO)	0.011	0.181	0.468	1.07	1.45
Distillate Fuel Oil					
Sulfur Dioxide (SO_2)	0.025	0.406	1.05	2.42	3.26
Nitrogen Dioxide (NO_2)	0.089	1.45	3.75	8.63	11.6
Particulates (PM_{10})	0.0059	0.097	0.246	0.524	0.772
Carbon Monoxide (CO)	0.024	0.394	0.999	2.15	3.14

[a] From the ISCST model and 5-years of hourly meteorological data from the NWS station at the Tampa International Airport, 1987-91.

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration 1-Hour	3-Hour	Plants
Sensitive	1,310 - 2,620 $\mu g/m^3$ (0.5 - 1.0 ppm)	790 - 1,570 $\mu g/m^3$ (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 $\mu g/m^3$ (1.0 - 2.0 ppm)	1,570 - 2,100 $\mu g/m^3$ (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 $\mu g/m^3$ (>2.0 ppm)	>2,100 $\mu g/m^3$ (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary AAQS

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[1]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[2,3]	Respiratory stress in mice	1,917	3 hours in mice
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[1]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: [1]Newman and Schreiber, 1988.
[2]Gardner and Graham, 1976.
[3]Trzeciak et al., 1977.

Table 7-5. Plume Visual Impact Analysis- Screening Level 2
Identification of Worst-Case Meteorological Conditions

Dispersion Conditions						Transport	Frequency of Occurrence (percent) of Dispersion Conditions [c]			
Stability		Wind Speed	Dispersion Parameter		Sigma Y x Sigma Z	Time to	Hours 7 p.m. to 7 a.m.		Hours 7 a.m. to 7 p.m.	
Category	Name	(m/s)	Horizontal (Sigma Y (m))	Vertical (Sigma Z (m))	x Wind Speed (m^3/s)	Class I Area (hours) [a]	f [b]	cf [b]	f	cf
							South Wind Direction			
F	Moderately Stable	0.8	663.0	66.9	35,488	9.7	0.49	0.49	0.04	0.04
E	Slightly Stable	0.8	995.6	123.2	98,137	9.7	0.00	0.49	0.00	0.04
F	Moderately Stable	2.6	663.0	66.9	115,336	3.0	1.38	$\boxed{1.87}$	0.11	0.15
F	Moderately Stable	4.4	663.0	66.9	195,184	1.8	0.00	1.87	0.00	0.15
D	Neutral	0.8	1329.5	239.1	254,304	9.7	0.06	1.93	0.03	0.18
E	Slightly Stable	2.6	995.6	123.2	318,944	3.0	1.20	3.13	0.18	0.36
E	Slightly Stable	4.4	995.6	123.2	539,751	1.8	0.40	3.53	0.13	0.49
D	Neutral	2.6	1329.5	239.1	826,488	3.0	0.31	3.84	0.47	0.95
D	Neutral	4.4	1329.5	239.1	1,398,672	1.8	0.85	4.70	1.00	$\boxed{1.95}$
							South- southeast Wind Direction			
F	Moderately Stable	0.8	663.0	66.9	35,488	9.7	0.34	0.34	0.01	0.01
E	Slightly Stable	0.8	995.6	123.2	98,137	9.7	0.00	0.34	0.00	0.01
F	Moderately Stable	2.6	663.0	66.9	115,336	3.0	1.09	$\boxed{1.43}$	0.05	0.06
F	Moderately Stable	4.4	663.0	66.9	195,184	1.8	0.00	1.43	0.00	0.06
D	Neutral	0.8	1329.5	239.1	254,304	9.7	0.01	1.44	0.02	0.08
E	Slightly Stable	2.6	995.6	123.2	318,944	3.0	1.04	2.47	0.09	0.17
E	Slightly Stable	4.4	995.6	123.2	539,751	1.8	0.56	3.03	0.04	0.21
D	Neutral	2.6	1329.5	239.1	826,488	3.0	0.21	3.24	0.37	0.58
D	Neutral	4.4	1329.5	239.1	1,398,672	1.8	0.72	3.96	0.55	$\boxed{1.13}$

[a] Based on proposed source located approximately 27.8 km from closest boundary of Class I area.
[b] f= frequencyfor given meteorological condition; cf= cumulative frequency up to and including condition.
[c] Based on surface meteorological data for 1987 to 1991 from the National Weather Service (NWS) station at the Tampa International Airport.

Figure 7-1 Level 1 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	30.00	LB /HR
NOx (as NO2)	200.10	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	2.40	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.06 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	27.80 km
Min. Source-Class I Distance:	27.80 km
Max. Source-Class I Distance:	47.80 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	135.	35.4	34.	2.00	4.420*	.05	.005
SKY	140.	135.	35.4	34.	2.00	2.021*	.05	-.035

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	6.530*	.05	.078*
SKY	140.	0.	1.0	168.	2.00	1.522	.05	-.068*

Figure 7-2 Level 1 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil Predicted at the Chassahowitzka NWA

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               ***  Level-1 Screening   ***
 Input Emissions for

   Particulates     51.00  LB /HR
   NOx (as NO2)   1086.00  LB /HR
   Primary NO2        .00  LB /HR
   Soot               .00  LB /HR
   Primary SO4      28.20  LB /HR

    **** Default Particle Characteristics Assumed

             Transport Scenario Specifications:

    Background Ozone:                   .06 ppm
    Background Visual Range:          65.00 km
    Source-Observer Distance:         27.80 km
    Min. Source-Class I Distance:     27.80 km
    Max. Source-Class I Distance:     47.80 km
    Plume-Source-Observer Angle:      11.25 degrees
    Stability:   6
    Wind Speed:   1.00 m/s

                           R E S U L T S

 Asterisks (*) indicate plume impacts that exceed screening criteria

          Maximum Visual Impacts INSIDE  Class I Area
            Screening Criteria ARE Exceeded
                                        Delta E      Contrast
                                      ===========  ============
 Backgrnd Theta Azi Distance Alpha Crit  Plume     Crit  Plume
 ======== ===== === ======== ===== ====  =====     ====  =====
  SKY      10.  84.   27.8     84.  2.00 16.108*    .05  -.028
  SKY     140.  84.   27.8     84.  2.00  8.393*    .05  -.121*

          Maximum Visual Impacts OUTSIDE Class I Area
            Screening Criteria ARE Exceeded
                                        Delta E      Contrast
                                      ===========  ============
 Backgrnd Theta Azi Distance Alpha Crit  Plume     Crit  Plume
 ======== ===== === ======== ===== ====  =====     ====  =====
  SKY      10.  40.   22.9    129.  2.00 17.020*    .05  -.033
  SKY     140.  40.   22.9    129.  2.00  8.686*    .05  -.144*
```

Figure 7-3 Level 2 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA

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

Input Emissions for

Particulates	30.00	LB /HR
NOx (as NO2)	200.10	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	2.40	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.06 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	27.80 km
Min. Source-Class I Distance:	27.80 km
Max. Source-Class I Distance:	47.80 km
Plume-Source-Observer Angle:	11.25 degrees

Stability: 4

Wind Speed: 4.40 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

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

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	145.	39.6	24.	2.00	.280	.05	.000
SKY	140.	145.	39.6	24.	2.00	.123	.05	-.002

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

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	1.281	.05	.006
SKY	140.	0.	1.0	168.	2.00	.406	.05	-.015

Figure 7-4 Level 2 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil Predicted at the Chassahowitzka NWA

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

Input Emissions for

Particulates	51.00	LB /HR
NOx (as NO2)	1086.00	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	28.20	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.06 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	27.80 km
Min. Source-Class I Distance:	27.80 km
Max. Source-Class I Distance:	47.80 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	4
Wind Speed:	4.40 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

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

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	145.	39.6	24.	2.00	1.310	.05	-.003
SKY	140.	145.	39.6	24.	2.00	.640	.05	-.011

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	5.	8.7	164.	2.00	2.251*	.05	-.006
SKY	140.	5.	8.7	164.	2.00	1.048	.05	-.024

Note: The results with Theta equal to 10 degrees are unrealistic because the plume is assumed to be between the observer and the sun which is located at an angle of 10 degrees above the horizon in a direction to the southeast or southwest of the observer. In reality, such a sun angle and direction are not likely to occur for any given line of sight from the Class I area to the project. By limiting the southward extent of sun's location to the east-southeast or west-southwest directions and to a 10-degree angle above the horizon, the Delta E for the project is estimated to be less than the criterion of 2.0.

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON "F" CLASS COMBUSTION TURBINE

(Note: SO_2 based on 0.2 gr/100 cf of H_2S. Actual total sulfur based on 1 gr/100 cf to account for odorant (mercaptans) in pipeline gas.)

Table A-1. Design Information and Stack Parameters for the Shady Hills Generating Station Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	179.2	172.2	156.6
Net heat rate (Btu/kWh, LHV)	9,319	9,361	9,591
(Btu/kWh, HHV)	10,344	10,391	10,646
Heat Input (MMBtu/hr, LHV)	1,670	1,612	1,502
(MMBtu/hr, HHV)	1,854	1,789	1,667
Fuel heating value (Btu/lb, LHV)	20,751	20,751	20,751
(Btu/lb, HHV)	23,006	23,006	23,006
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	4,063,400	3,919,300	3,672,900
- provided	3,694,000	3,563,000	3,339,000
Temperature (°F)	1,097	1,113	1,135
Moisture (% Vol.)	7.9	8.6	10.3
Oxygen (% Vol.)	12.60	12.50	12.20
Molecular Weight	28.44	28.34	28.16
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,670	1,612	1,502
Heat content (Btu/lb, LHV)	20,751	20,751	20,751
Fuel usage (lb/hr)- calculated	80,478	77,683	72,382
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
Turbine Flow Conditions			
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	4,063,400	3,919,300	3,672,900
Temperature (°F)	1,097	1,113	1,135
Molecular weight	28.44	28.34	28.16
Volume flow (acfm)- calculated	2,706,395	2,645,986	2,530,918
(ft3/s)- calculated	45,107	44,100	42,182
Velocity (ft/sec)	118.7	116.0	111.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 1998.

Table A-2. Maximum Emissions for Criteria Pollutants for the Shady Hills Generating Station Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Gas	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation		3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr		10	10	10
Emission rate (lb/hr)- provided		10.0	10.0	10.0
(TPY)		17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)		0.0448	0.0448	0.0448
Fuel use (cf/hr)		1,797,031	1,734,619	1,616,252
Sulfur content (grains/ 100 cf)		1	1	1
lb SO_2 /lb S (64/32)		2	2	2
Emission rate (lb/hr)		5.1	5.0	4.6
(TPY)		8.70	8.40	7.83
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2		9	9	9
Moisture (%)		7.9	8.6	10.3
Oxygen (%)		12.6	12.5	12.2
Turbine Flow (acfm)		2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)		1,097	1,113	1,135
Emission rate (lb/hr)		66.7	64.1	59.9
(TPY)		113.0	108.6	101.6
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd		12	12	12
Moisture (%)		7.9	8.6	10.3
Turbine Flow (acfm)		2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)		1,097	1,113	1,135
Emission rate (lb/hr)		44.2	42.5	39.3
(TPY)		75.0	72.0	66.6
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd		1.4	1.4	1.4
Moisture (%)		7.9	8.6	10.3
Turbine Flow (acfm)		2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)		1,097	1,113	1,135
Emission rate (lb/hr)		2.95	2.83	2.62
(TPY)		5.0	4.8	4.4
Lead (lb/hr)= NA				
Emission Rate Basis		NA	NA	NA
Emission rate (lb/hr)		NA	NA	NA
(TPY)		NA	NA	NA

Note: ppmvd = parts per million, volume dry; O_2 = oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for the Shady Hills Generating Station Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Gas Ambient Temperatu 32 °F	 59 °F	 95 °F
Hours of Operation	3,390	3,390	3,390
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	1.20E-06	1.20E-06	0.00E+00
Heat Input Rate (MMBtu/hr)	1.85E+03	1.79E+03	1.67E+03
Emission Rate (lb/hr)	2.22E-09	2.15E-09	0.00E+00
(TPY)	3.77E-09	3.64E-09	0.00E+00
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.39E-06	1.34E-06	1.25E-06
(TPY)	2.35E-06	2.27E-06	2.11E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	1,797,031	1,734,619	1,616,252
Sulfur (lb/hr)	2.57	2.48	2.31
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	10	10	10
Emission Rate (lb/hr)	0.79	0.76	0.71
(TPY)	1.33	1.29	1.20

Sources: (a) Golder Associates, 1998; (b) EPA, 1981; (c) Assumed.

Note: No Emission Factors for Hydrogen chloride (HCl) from natural gas firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the Shady Hills Generating Station Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperat 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.48E-03	1.43E-03	1.33E-03
(TPY)	2.51E-03	2.43E-03	2.26E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	34	34	34
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	6.30E-02	6.08E-02	5.67E-02
(TPY)	1.07E-01	1.03E-01	9.61E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1.85E+03	1.79E+03	1.67E+03
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b), lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a), lb/10^{12} Btu	10	10	10
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.85E-02	1.79E-02	1.67E-02
(TPY)	3.14E-02	3.03E-02	2.83E-02

Sources: (a) Golder Associates, 1998; (b) EPA, 1996 (AP-42, Table 3.1-4)

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions
Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **74.4** lb/hour **34.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.7 lb/hour 11.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-SPC; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7 ppmvw	4. Equivalent Allowable Emissions: 16.7 lb/hour 8.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A; high and low load	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if <400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for oil firing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number: Serial Number:	
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

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

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

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

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

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

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

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

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

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

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[ ] 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.

2. 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.

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

Unreg. Emissions Activities - 1 Tank 2.8 M gallons each

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

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

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit information section addresses one 2.8 million gallon tank as unregulated emission unit. NSPS Subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards. See Attachment PSD-SPC.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):	
2. Control Device or Method Code(s):	

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Oil/Diesel**		
2. Source Classification Code (SCC): **A2505030090**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **41,100**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **131.8**
10. Segment Comment (limit to 200 characters): **Annual rate combined for both tanks based on inputs to CTs; 18,560 Btu/lb (LHV); and 7.1 lb/gal at 59°F.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

PART B

ATTACHMENT PSD-SPC

PSD ANALYSIS

1.0 INTRODUCTION

IPS Avon Park Corporation proposes to license, construct, and operate a nominal 540-megawatt (MW) power production facility, referred to as the Shady Hills Generating Station, in an unincorporated area of Pasco County, Florida (Figure 1-1). The site will be located on approximately a 20-acre tract of land near Pasco County's resource recovery facility and Shady Hills wastewater treatment plant. The project consists of three 170-MW dual-fuel, General Electric Frame 7FA combustion turbines (CTs) that will use dry low-nitrogen oxide (NO_x) [dry-low NO_x (DLN)] combustion technology when operating on natural gas and water injection (for NO_x control) when operating on distillate fuel oil. The facility is designed for peaking service. The primary fuel of the CTs will be natural gas with distillate fuel oil used as backup fuel. The fuel oil in this case will contain a maximum sulfur content of 0.05 percent.

The project requires an air construction permit and prevention of significant deterioration (PSD) review. To assist in performing the necessary licensing activities, IPS Avon Park Corporation hired Golder Associates Inc. (Golder) to perform the necessary air quality assessments for determining the project's compliance with state and federal new source review (NSR) regulation. The critical aspects of these assessments include the air quality impact analyses performed using an air dispersion model and the best available control technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed project will be a new air pollution source that will result in increases in air emissions in Pasco County. The U.S. Environmental Protection Agency (EPA) has implemented regulations for facilities requiring a PSD review. The PSD regulations are promulgated under 10 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation to the Florida Department of Environmental Protection (DEP). Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.). Florida's regulations incorporate the EPA PSD regulations.

Based on the emissions from the proposed project, a PSD review is required for each of the following regulated pollutants:

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% and load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - 32°F; 100% load; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 gram/100 cf - 32°F, 100% load; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 74.4 lb/hour 86.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2

8. Calculation of Emissions (limit to 600 characters):

See Attachment PSD-SPC; Section 2.0; Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 20 ppmvd	4. Equivalent Allowable Emissions: 74.4 lb/hour 34.7 tons/year

5. Method of Compliance (limit to 60 characters):

EPA Method 10; high and low load

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

Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 1998; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See Attachment PSD-SPC; Section 2.0; Appendix A.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**
4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 10; high and low load
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.7 lb/hour 11.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-SPC; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7 ppmvw	4. Equivalent Allowable Emissions: 16.7 lb/hour 8.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 25A; high and low load	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if <400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for oil firing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number: Serial Number:	
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA Combustion Turbine

4. Emissions Unit Identification Number:
ID:

[ ] No ID
[X] ID Unknown

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

9. Emissions Unit Comment: (Limit to 500 Characters)
This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment PSD-SPC.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion - Natural gas firing**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **172** MW	
3. Incinerator Information: Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F	

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**
2. Control Device or Method Code(s): **28**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **172**	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,612	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	3,390	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,806 MMBtu/hr (ISO-LHV) and 182 MW.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment IPS-EU1-D for operational requirements	
See Attachment PSD-SPC for permitting requirements	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Att. PSD-SPC**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,645,000** acfm	10. Water Vapor: **8.6** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **347.0** North (km): **3139.0**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**		3. SCC Units: **1,000 gallons used**
4. Maximum Hourly Rate: **13.7**	5. Maximum Annual Rate: **13,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 131.8 (rounded to 132). Based on 7.1 lb/gal; LHV of 18,560 Btu/lb, - ISO conditions, 1,000 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**		3. SCC Units: **Million Cubic Feet**
4. Maximum Hourly Rate: **1.70**	5. Maximum Annual Rate: **5,752**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if < 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - 32°F; 100% load; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2

2. Total Percent Efficiency of Control:

3. Potential Emissions: 101.5 lb/hour 55.3 tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
Reference: GE, 1998; Golder

7. Emissions Method Code: 2

8. Calculation of Emissions (limit to 600 characters):

See Attachment PSD-SPC; Section 2.0; Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: See Comment

4. Equivalent Allowable Emissions: 5.1 lb/hour 8.4 tons/year

5. Method of Compliance (limit to 60 characters):

Fuel Sampling

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

Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 gram/100 cf - 32°F, 100% load; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_x	2. Total Percent Efficiency of Control:
3. Potential Emissions: 362 lb/hour 252 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-SPC; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 9 ppmvd	4. Equivalent Allowable Emissions: 66.7 lb/hour 108.6 tons/year
5. Method of Compliance (limit to 60 characters): CEM - 30 Day Rolling Average	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. Gas firing, 1 gram/100 cf - 32°F, 100% load; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **74.4** lb/hour **34.7** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7 ppmvw**	4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 17 lb/hour 20.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-SPC; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 17 lb/hr	4. Equivalent Allowable Emissions: 17 lb/hour 8.5 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test; EPA Method 5 or 17 if <400 hours	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for oil firing.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-SPC [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-SPC [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA Combustion Turbine

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

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

9. Emissions Unit Comment: (Limit to 500 Characters)
This emission unit is a GE Frame 7FA combustion turbine operating in simple cycle mode. See Attachment PSD-SPC.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):   **Dry Low NO_x combustion - Natural gas firing**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating:	**172** MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**	
2. Control Device or Method Code(s): **28**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,612	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	3,390	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			
Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,806 MMBtu/hr (ISO-LHV) and 182 MW.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment IPS-EU1-D for operational requirements	
See Attachment PSD-SPC for permitting requirements	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Att. PSD-SPC**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through a single stack.

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

5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,645,000** acfm	10. Water Vapor: **8.6** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **347.0** North (km): **3139.0**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **13.7**	5. Maximum Annual Rate: **13,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 131.8 (rounded to 132). Based on 7.1 lb/gal; LHV of 18,560 Btu/lb, - ISO conditions, 1,000 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.70**	5. Maximum Annual Rate: **5,752**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 3,390 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if < 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-SPC; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-SPC; Section 2.0; Appendix A.**	